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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS EASTERN GROUP AND FOR CERTAIN RELATED APPROVALS.	Docket No. W-01445A-02-0619 **NOTICE OF FILING REBUTTAL TESTIMONY**

Applicant, Arizona Water Company, hereby files the Rebuttal Testimony of William M. Garfield, Michael J. Whitehead, Thomas M. Zepp and Ralph J. Kennedy, Sheryl L. Hubbard, Walter W. Meeks in the above-captioned docket.

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DATED this 5th day of August, 2003.

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An original and 13 copies of the foregoing, and attached documents were delivered this 5th day of August, 2003, to:

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A copy of the foregoing was Delivered/mailed this 5th day of August, 2003, to:

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ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

REBUTTAL TESTIMONY & EXHIBITS

OF

William M. Garfield

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS EASTERN GROUP AND FOR CERTAIN RELATED APPROVALS.	Docket No. W-01445A-02-0619

REBUTTAL TESTIMONY OF WILLIAM M. GARFIELD

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q. WHAT IS YOUR NAME, EMPLOYER AND OCCUPATION?

A. My name is William M. Garfield. I am employed by Arizona Water Company (the "Company") as President.

Q. ARE YOU THE SAME WILLIAM M. GARFIELD THAT PREVIOUSLY PROVIDED DIRECT TESTIMONY IN THIS MATTER?

A. Yes, although since then I have been promoted to President of the Company following the retirement of James R. Livingston on July 18, 2003.

Q. DO YOU HAVE ADDITIONAL QUALIFICATIONS AND EXPERIENCE NOT PREVIOUSLY PROVIDED IN YOUR DIRECT TESTIMONY THAT YOU BELIEVE ARE GERMANE TO YOUR REBUTTAL TESTIMONY?

A. Yes, I was a member of a municipal water provider workgroup that worked with the Arizona Department of Water Resources ("ADWR") to develop the Third Management Plan for the Pinal and Phoenix Active Management Areas ("AMA"). This workgroup studied and advised the ADWR on residential water demands, water distribution system lost water requirements, and other water use characteristics related to conservation requirements. Also, since filing direct testimony in this matter, I have been appointed to the Water Infrastructure Finance Authority Board of Directors, the Water Utility Association of Arizona Board of Directors, and I have been elected Chairman of the Water Management Subcommittee of the Pinal Active Management Area Groundwater Users Advisory Council.

II. PURPOSE AND EXTENT OF TESTIMONY

Q. WHAT IS THE PURPOSE AND EXTENT OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to provide testimony either in support of, or to rebut, the testimony filed by Utilities Division Staff ("Staff") and RUCO, and also to provide additional testimony on behalf of the Company to further support its requested rate increases. Specifically, I will be addressing John Thornton's testimony as it relates to the conservation issues raised by Staff's tiered rate design proposal; Lyndon Hammon's testimony as it relates to water loss and water system maintenance; Ron Ludders' and Mr. Hammon's testimony related to the so-called PCG matter; as well as certain issues raised by RUCO witnesses relating to rate consolidation and the PCG matter, including the treatment of the PCG monetary payment received by the Company in the PCG settlement. Finally, I will comment on certain issues concerning "risk" as it relates to cost of capital analysis.

Q. WOULD YOU PLEASE SUMMARIZE THE COMPANY'S REBUTTAL POSITION?

A. Yes, there appear to be several key issues in dispute. These issues include: 1) return on equity; 2) treatment of the settlement payment received by the Company from the Pinal Creek Group ("PCG"); 3) rate design; 4) rate consolidation for Apache Junction and Superior; 5) recovery of deferred Central Arizona Project ("CAP") payments; 6) working capital allowance; and 7) elimination of purchased water and purchased power adjuster mechanisms ("PWAM" and "PPAM"). An eighth key issue, post test year plant additions ("PTYPA"), will be resolved if Staff corrects for errors in allocating the Phoenix Office and Coolidge Meter Shop PTYPA as identified in Ms. Hubbard's rebuttal testimony.

More specifically, Staff and RUCO recommend an insufficient return on equity that: 1) fails to recognize the increased risk to the Company due to its relative small size (compared to the larger, more diversified companies to which it is being compared), impact from the new arsenic maximum contaminant level, and other regulatory risks not faced by the companies to which it is being compared; 2) fails to recognize the benefits received by the Company's customers as a result of receiving water service from a well-run, financially responsible company that operates as a single economic unit, although composed of small individual systems with separate rates; 3) fails to recognize the returns on equity that investors require to invest in a company such as the Company; and 4) fails to recognize returns on equity recently authorized by other public utility commissions for companies less risky than the Company.

The Company objects to Staff's and RUCO's recommendations to take all, or a part of, the settlement payment received by the Company from the PCG because the recommendations: 1) constitute confiscatory and retroactive ratemaking; 2) promote bad public policy by removing financial incentives for water utilities to pursue polluters; 3) fail to recognize the significant extent of benefits received by Miami customers solely from the successful efforts of the Company; and 4) are contrary to proper accounting guidelines, which have been carefully followed by the Company.

The Company objects to Staff's marginal cost based tiered rate design proposal because: 1) the proposed rate design shifts the cost of service from small users to larger users for both commodity and minimum bill components; 2) no cost of service study has been performed by Staff to justify the new rate design; 3) marginal cost pricing for inverted block water rate design is experimental in nature and has never been approved by the Commission; 4) Staff has not assessed the adverse impact on large users, such as schools, hospitals and industrial customers; 5) Staff has failed to address the revenue instability effects inherent in tiered rate design that will result in greater risk to the Company; 6) Staff has failed to justify the need for a tiered rate design; 7) Staff's rate design applies the same water use blocks to all of the Eastern Group systems, without considering water uses for each water system; and 8) Staff's use of tiered rates contradicts the Arizona Department of Water Resources' conclusion that there is little or no potential for conservation for several of these water systems.

The Company objects to Staff's and RUCO's recommendations that Apache Junction and Superior not be consolidated, failing to recognize the significant benefits customers of both water systems would receive. The Company's request to consolidate these systems in two steps should be approved.

The Company objects to Staff's proposed amortization schedule for recovery of deferred payments made by the Company for CAP water because it extends well beyond the periods of time authorized by the Commission for recovery of these same deferred charges by other water utilities, such as Sun City Water which was authorized to recover these same deferred charges over five (5) years. Recovery of these charges should not be stretched out over the ten (10) years RUCO recommends, and certainly not the thirty-two (32) to thirty-four (34) year time period that Staff recommends.

The Company objects to Staff's working capital allowance, primarily due to Staff's incorrect lead-lag analysis of property taxes, grossly overestimating the lag between property tax accruals and the actual date that property taxes are paid. The result of this overstatement of lag-time understates the Company's working capital allowance. The Company's working capital allowance should be accepted and Staff's recommendation should be rejected.

Staff proposes to eliminate PWAM and PPAM adjuster mechanisms for the Eastern Group. These adjuster mechanisms should be retained in their current form because they: 1) provide a mechanism for adjustments to rates based on actual changes in purchased power or purchased water, no more no less, which protects both the customers and the utility; 2) the detailed accounting necessary for implementing actual changes in PWAM and PPAM is performed by the Company, expediting Staff's review and approval; 3) allow the Company to defer a general rate proceeding that would otherwise be needed; and 4) PWAM and PPAM adjusters are administratively efficient and have proven successful for many years.

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III. STAFF'S PROPOSED RATE DESIGN

Q. DO YOU AGREE WITH STAFF THAT THERE SHOULD BE A LIFELINE RATE WITH THE FIRST 3,000 GALLONS PRICED 20% BELOW THE AVERAGE COMMODITY COST?

A. No. Staff's witness, Mr. Thornton, applies the same lifeline block of 3,000 gallons for all customers in all eight Eastern Group systems, regardless of the customer class or meter size. First of all, there is no ADEQ engineering guideline that establishes a lifeline block rate for water rate design. *See* Thornton Direct at 2, ls. 18-20.

The Company also opposes the proposed lifeline rate block because it does not distinguish between "basic" or "consumptive" uses, between differences in uses among water systems, or between differences in uses among customer classes. Staff's universal lifeline proposal is, in reality, merely a means of <u>subsidizing</u> residential rates at the expense of commercial and industrial customers under the guise of "conservation" without assessing the financial impact on such customers.

To produce a lifeline rate, Staff's three-tiered rate design would raise costs disproportionately to schools, hospitals, and other places of business and industry. This is true because, in the end, Staff's proposal unduly places the cost of establishing a "lifeline" block of water primarily for certain residential customers on other customers (including residential customers in apartments or mobile home parks served through a master meter) that also rely upon water for their businesses or livelihoods, in a manner completely contrary to cost of service rate making that this Commission has traditionally followed to equitably allocate rates among water users.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE TYPE OF SUBSIDY THAT YOU HAVE JUST DESCRIBED?

A. Yes, looking at Schedule REL-26, page 1, the first block is set at 3,000 gallons, the second set from 3,001 to 50,000 gallons and the third block is for all water use above 50,000 gallons. These three blocks have commodity rates of $1.5008, $1.8760 and $2.2512 per 1,000 gallons, respectively. Using a mobile home with a single 5/8-inch by 3/4-inch water meter and a mobile home park with 300 individual mobile homes served by a 6-inch master water meter, and assuming equal occupancies and water use for each individual mobile home, estimated at 13,000 gallons per month, the following monthly charges would result:

EXAMPLE

	Individual Mobile Home	Mobile Home Park (300 Mobile Homes)
Total Water Use	13,000 Gals.	3,900,000 Gals. (300 Times 13,000)
First Block	$4.50 (3,000 Gals.)	$4.50 (3,000 Gals.)
Second	$18.76 (10,000 Gals.)	$88.17 (47,000 Gals.)
Third Block	N/A	$8667.12 (3,850,000 Gals.)
Total Commodity Cost	$23.26	$8759.79
Cost Per Home	$23.26	$29.20

The above example clearly illustrates the potential "subsidy" effect of Staff's proposed three-tiered rate design as well as an unwarranted 25% differential between two residential customers. This is not where the problem ends, however, as the rate design proposed by Staff (*see* Schedule REL-26, page 1) further shifts the costs from the residential customer class to the commercial customer class by establishing new minimum bill multipliers that differ significantly from the Company's minimum bill multipliers established through a cost of service study in the Company's 1992 general rate proceeding. *See* ACC Decision No. 58120 (December 23, 1992). The following table illustrates the shift of minimum bill multipliers proposed by the Staff:

Meter Size	Existing Minimum (Multiplier)	ACC Proposed Minimum (Multiplier)
⅝" by ¾"	$12.43	$12.43
1"	$24.86 (2.0)	$35.71 (2.9)
2"	$62.15 (5.0)	$113.80 (9.2)
3"	$103.58 (8.3)	$283.79 (22.8)
4"	$207.16 (16.7)	$532.97 (42.9)
6"	$362.53 (29.2)	$717.50 (57.7)

However, Staff has not supported this significant increase in minimum bill multipliers by any cost of service or other appropriate study. Instead, Staff seeks to subsidize certain residential customers by shifting revenue requirements to commercial and other non-residential customers with no basis whatsoever for such a change, except Mr. Thornton's testimony that Staff's proposed rate design serves the greater "social good." *See* Thornton Direct at 5, ls. 24-29 and 11, ls. 3-4.

Q. DOESN'T MR. THORNTON TESTIFY THAT STAFF'S PROPOSED THREE-TIERED RATE DESIGN PROMOTES CONSERVATION?

A. Yes, Mr. Thornton attempts to justify Staff's proposal on such a basis but his own testimony shows that this approach is not effective in promoting conservation. A three-tiered rate design is a form of inverted rate design and Mr. Thornton admits that the three-tiered rate design will probably not result in any conservation of water. Thornton Direct at Executive Summary and at 5, l.31-6, l.3. Nevertheless, Mr. Thornton opines that it will send a pricing signal to the customer that water is a scarce commodity and result in long term changes in water use by customers referring to the American Water Works Association ("AWWA") Manual M-1, concerning the establishment of a third tier rate based on marginal pricing. *Id.* at 3, ls. 5-7. I find it remarkable that Mr. Thornton relies so heavily on materials Staff, in the Company's recent Northern Group rate proceeding, criticized as being strictly an introductory or elementary level reference used merely to introduce the concepts of cost analysis. *See* Transcript, October 3, 2002 Hearing (Docket No. W-01445A-00-0962) at 215.

In any event, water rates should be based on cost of service ratemaking principles and the determination of potential adverse effects. The AWWA's basic conditions for rate making are as follows: "The first goal of any rate structure is to generate sufficient revenues to maintain efficient and reliable utility operations, and the second is fairness in the allocation of utility service costs." AWWA Mainstream publication, originally approved by AWWA Government Affairs Committee on June 28, 1995, attached hereto as Exhibit WMG-1. The AWWA's position on conservation rates also provides that "Conservation oriented water rate structures by themselves do not constitute an effective water conservation program." *Id.*

Q. MR. GARFIELD, IS THERE A NEED FOR THE EASTERN GROUP SYSTEMS TO REDUCE WATER USE THROUGH CONSERVATION EFFORTS?

A. No. The Company's Apache Junction, Superior, and Oracle systems are not required to reduce water use since ADWR has already determined that existing water use is highly efficient and there is no conservation potential or need to further reduce water use. The ADWR's Third Management Plans for the Phoenix and Tucson AMAs show no reduction in water use is necessary for these three water systems for compliance with conservation measures. This is exceptional,

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since only a few of the many water systems in these AMAs are in a similar position. All but a few are required to reduce water use over the next ten years. Thus, although Staff has introduced a measure that is purportedly needed to help conserve water, ADWR has determined that no further conservation is required.

Q. **DO YOU AGREE WITH MR. THORNTON THAT CONSOLIDATED RATES ARE INAPPROPRIATE FOR WATER SYSTEMS WHOSE EMBEDDED COSTS VARY FROM SYSTEM TO SYSTEM AND WHO DERIVE NO APPARENT BENEFIT FROM CONSOLIDATION?**

A. No. The Company has requested the Commission to allow consolidation of the Apache Junction and Superior CC&Ns, a first step toward the Company's plans for physical consolidation of these two water systems. In that proceeding, Staff recommends consolidating the two service areas largely because of the cost of arsenic treatment. Superior and Apache Junction are both impacted by the new arsenic MCL and consolidating rates is one way of spreading these costs over a larger base of customers. In addition, since these water systems depend upon the same overall water supplies, it makes good engineering sense to consolidate these systems for long-term water resource planning purposes. Also, the use of CAP water in Superior can only be accomplished by interconnecting these systems.

Mr. Thornton incorrectly claims that there is no apparent benefit to consolidation, but fails to note that these systems already share resources. See Thornton Direct at 10, ls. 16-18. Earnings in one system shore up or subsidize the lack of earnings in the other system. This is clearly the case with Apache Junction and Superior. The arsenic issue alone, however, provides an opportunity to spread costs across a much larger customer base leading to lower overall costs to all customers. Administration and operations oversight of arsenic water treatment plants will be more efficient under one operation than many.

Q. DO YOU AGREE WITH MR. LUDDERS THAT THERE IS NO INCENTIVE TO REDUCE WATER USAGE UNDER UNIFORM RATES?

A. No, I do not. Mr. Ludders' comment (*see* Ludders Direct at 16, l. 9) that customers have no incentive to reduce water use under uniform rates has no foundation and is clearly inaccurate. The Company's San Manuel customers, many of whom provided public comments on June 23, 2003, voiced their concerns that they may have to reduce water use after water rates increase because they are retired and on a fixed income and cannot afford to pay more for water. Customers that use more water and demand a higher level of service from the Company pay more than those customers that use less water and have a significant incentive to reduce water use through changes in water use habits, use of low-flow fixtures, etc. Uniform rates do not translate to a flat bill. Customers pay for the quantity of water they use.

Nevertheless, Mr. Thornton and Mr. Ludders testify that water is a finite resource requiring the implementation of a more complex rate structure, and allege this has been done nationally and internationally. *See* Thornton Direct at 4, ls. 13-19; Ludders Direct at 16, ls. 9-12. In fact, tiered rates are much less common than uniform rates in Arizona. The predominant rate design in Arizona is a uniform rate design, easy for customers to understand, simple to administer, and producing predictable revenue. Staff's proposed three-tiered rate design is not based on cost of service principles, a long established standard of rate making, nor has Staff considered any of the disadvantages of three-tiered rates, such as revenue instability, subsidization of small users by large users, and the shift of the true cost of service from small users to large users. Staff further fails to address the fact that the imposition of three-tiered rates, without assessing each water system's individual, case-by-case specific water use and supply demographics, violates the

Commission's own policy on the application of these types of rate designs. Commission Working Group Report Attachment C, attached as Exhibit WMG-2.

Q. WHAT IS YOUR ASSESSMENT OF STAFF'S RECOMMENDED RATE DESIGN FOR APACHE JUNCTION?

A. My experience and review of water system operating statistics shows that very few residential customers use over 50,000 gallons of water per month. The Company opposes the shift in cost from small users to large users, which is not supported by a cost of service study and which also contradicts accepted rate-making principles. Furthermore, the rates set forth in Mr. Ludders' testimony (*see* Staff Schedule REL-26, Page 1) would give a discount to certain customers by maintaining the same monthly minimum bill for those customers, a rate that has been in place over 10 years, while simultaneously raising the monthly minimum bills to 1-inch and larger meters irrespective of any cost of service principles. The Company also objects to the rate design for the monthly minimum bills for the other systems in the Eastern Group on similar grounds, i.e., raising rates disproportionately between customer classes is inappropriate and should be rejected.

V. <u>STAFF'S ENGINEERING TESTIMONY</u>

Q. HAVE YOU REVIEWED THE STAFF TESTIMONY ON ENGINEERING ISSUES?

A. I have reviewed the testimony and recommendations made by Mr. Hammon in this matter. To begin with, the Company objects to reducing the allowable pumping expenses for Miami by $39,000. Mr. Hammon's explanation for the reduction is based on a misunderstanding of the PCG Agreement, is incorrect and does not provide a known and measurable basis for such an adjustment. *See* Hammon Direct at 18, ls. 20-22. As a consequence, this adjustment is contrary to traditional ratemaking principles and penalizes the Company.

The Company also disagrees with Mr. Hammon's assumption that well power and transport power is a 50/50 split. *See* Direct Testimony of Lyndon Hammon ("Hammon Direct") at 18, ls. 5-17. This assumption ignores the specific information inherent in the Company's Miami water system operating statistics. The Miami water system consists of many deep wells pumping from a depth approaching 1000 feet below land surface. Well power costs are higher in Miami than in most systems due to the depth of groundwater. Mr. Hammon ignores the specific water system operating statistics that compare high well power use to booster power use. His adjustment to power is therefore wrong and without known and measurable supporting evidence. This is in addition to the fact that the quantity of replacement water provided by the PCG to the Company is variable and subject to change if the facilities are transferred to the Company.

Q. ARE THERE OTHER AREAS OF DISAGREEMENT?

A. Yes. The Company also disagrees that curtailment tariffs should be required as part of this rate proceeding, particularly given Staff's view that any curtailment tariff should simply conform to the sample tariff prepared by the Staff. While the Company is in the process of preparing a master, company-wide curtailment tariff, the template prepared by the Staff would remove the water system operator's professional discretion in its operation of its water systems. To my knowledge, the Staff has no operating experience upon which to base its curtailment plan. Instead, because this issue potentially affects all water companies, Staff should solicit stakeholder input to draft rules to prescribe the process through which, and the conditions under which, water companies would have authority to implement water use curtailment plans. This issue is not appropriate for this general rate application.

Q. DO YOU AGREE WITH STAFF'S TESTIMONY CONCERNING

CHLORINATION EXPENSES?

A. No. The Company's pro forma adjustments to chlorination expenses do, in fact, meet the "known and measurable" test. *See* Hammon Direct at 11, ls. 17-19. The Company's pro forma adjustments are based on known labor costs ($/hour), known chemical costs ($/pound), the number of chlorination sites, labor hours to operate and maintain each chlorination facility, and amount of chemicals consumed per site. *See* the Company's Schedule C-1 Pages 1-5. The Company used known and measurable labor and chemical costs, and determined, based on best professional operational experience, the amount of time each employee would spend maintaining each facility and the quantity of chemicals used. The Company does not object to the use of 2002 recorded expenses, rather than the Company's pro forma adjustments, but submits that its pro forma adjustments are "known and measurable" for the reasons stated above.

Q. DO YOU AGREE WITH STAFF'S RECOMMENDATION ON THE NON-POTABLE RATE DESIGN?

A. No, I do not agree with Mr. Hammon's testimony concerning eliminating the fixed meter charge, and the requirement for the Company to install protective equipment. *See* Hammon Direct at 14-16. Again, there has been no cost of service study presented to justify such changes. In order to reduce groundwater pumping and encourage use of CAP water, the Company's current non-potable rates were designed to avoid shifting costs to potable water users. There are certain expenses related to the operation and maintenance of non-potable accounts that would be shifted to customers using potable water under Mr. Hammon's recommendations. Customers served under these tariffs represent large water users, and generate no income for the Company. Ultimately, Staff's approach would shift these costs to the Company's potable customers.

Also, the Company cannot accept Staff's recommendation that the Company hold the customer harmless from certain damages that might be prevented by protective equipment and the reference to the SLV Properties formal complaint. *See* Hammon Direct at 14-16. Mr. Hammon neglects to note that all of these facilities were designed and installed by customers and contributed to the Company. Power is supplied to the electronic meters by the non-potable customers. Any power surge that may develop comes from the customers' facilities, which the customer controls. Any protective device needed should be installed by, and be the responsibility of, the customer. The SLV Properties formal complaint has already been decided by the Commission (*see* Decision No. 65755 (March 20, 2003)) and Staff seems to simply want another bite at the apple, apparently disagreeing with the Commission's decision on that matter. That matter should not be subject to further consideration in this case.

Q. DO YOU AGREE WITH STAFF'S TESTIMONY CONCERNING WATER LOSS?

A. No, I do not agree with Staff concerning water loss for the Eastern Group water systems or with Staff's recommendations that water systems should keep water losses less than 10% and that water losses should never exceed 15%. *See* Hammon Direct at 4, l. 23. As I testified earlier, knowledge of water system operations is critical to the ability to determine water loss. Mr. Hammon's statement about allowable water loss percentages is without any foundation. I have reviewed the non-account water percentages that Mr. Hammon lists in his direct testimony (*see* Hammon Direct at 4, ls. 11-19) and I conclude that the percentages he utilizes reflect the percentage of water that was not sold to customers, not the percentage of water that was lost due to true "water losses" from water systems. For example, water used to overflow water storage tanks, flush water distribution systems, or provide water for fire protection are just a few examples of unsold water that are essential to operating and maintaining a water system and serving non-billable community water needs.

Moreover, the use of percentages to evaluate water system operation and distribution efficiencies has long been discounted. A water system is comprised of pipe that has an allowable leakage even when newly installed. The amount of total leakage is a function of pipe diameter, length of pipe, water pressure, age of pipe, etc. Therefore, a water system with more pipe per customer, or with higher operating pressures, would experience more water loss than a similar customer base with less water pipe per customer or with lower operating pressures.

Q. ARE THERE OTHER FACTORS THAT MUST BE CONSIDERED?

A. Yes, for instance, another variable that can greatly affect water system losses, when expressed as a percentage of water produced, is the amount of water delivered to a system's customers. Take for example, two identical water systems, i.e., water systems with identical pipes and identical water leaks, leaking at a rate of 100 gpm, with average water deliveries of 500 gpm and 1000 gpm, respectively. The water system that delivers 1000 gpm on the average and loses 100 gpm from its distribution system would have a 9.1% water loss (100 gpm divided by 1100 gpm) and the water system that delivers 500 gpm would have a 16.7% water loss rate. Both water systems are identical, however, and their operational efficiency is identical. Nevertheless, based on the standard that Mr. Hammon espouses for Staff, one water system would be characterized as inefficient due to its 16.7% water loss.

These factors are some of the reasons why Bisbee, Superior, San Manuel, and Oracle have higher actual, or apparent, water losses than most systems. More pipe, more pressure, less sales, all result in higher percentages of water losses.

Pressures in Superior are near 1000 PSI, with 23 miles of pipe before the first customer. Pressures in Bisbee and Oracle approach 500 PSI and 300 PSI, respectively, with similar pipe footage before the first customer. San Manuel is a water system with 20% less customers and lower sales per customer than 4 years ago, which has the effect of raising the apparent water loss when expressed as a percentage. Yet, actual water losses have not increased in San Manuel over the same time period.

Q. DO YOU HAVE CONCERNS ABOUT STAFF'S TESTIMONY REGARDING A METER TESTING AND IMPROVEMENT PROGRAM?

A. Yes. By suggesting that the Company determine the cost to implement or improve a meter testing and replacement program (*see* Hammon Direct at 5, l. 15), Mr. Hammon apparently does not know about the Company's meter maintenance program or the Company's Coolidge meter shop, which Staff has relied upon for many years to perform meter testing for other water companies. The Company's highly experienced and trained meter repair technicians have provided first hand instruction to Staff's engineering personnel over the years and the Company's Coolidge meter shop is regarded as one of the best meter repair facilities in the Southwest, a status that has been earned with years of continued excellence in the meter industry.

In addition, Mr. Hammon is apparently unfamiliar with the Company's meter maintenance program. The Company's meter maintenance program tracks gallons used and years in service for each size and type of meter. Random testing of meters is also performed to assess the effectiveness of the Company's meter maintenance program and is periodically adjusted to reflect greater efficiencies. Mr. Hammon also fails to note that for all meter testing by the Commission at the request of the Company's customers, meter accuracy results were exceptional.

Concerning assessing benefits and savings from incremental reductions in water losses, Mr. Hammon is apparently unaware of the Company's monthly operating water loss reports that describe the cost of lost water based on recent source of supply costs and the amount of expense saved with each 1% reduction in water loss.

Mr. Hammon recommends that the Company determine the cost to identify leaks, and repair water mains after leaks are found. (*See* Hammon Direct at 5, ls. 16-17. Contrary to Mr. Hammon's implications, the Company repairs all leaking water mains once leaks are identified.

Concerning the cost of performing leak audits and/or water system leak surveys, Mr. Hammon apparently is unaware of the Company's leak surveys. The Company's experience with leak surveys shows that except for extreme circumstances, the Company's water system personnel are in a better position to isolate the causes of leaks and to make repairs than using third-party leak locating service companies. The Company's personnel are also provided with several types of leak detection equipment to identify sources of leaks. Minimizing water losses is an ongoing effort and water losses tend to be cyclical in nature. Water system losses vary over time and efforts to locate leaks are driven by the level of water loss, cost of water losses and the ability to reduce water loss through various efforts.

VI. <u>RATE OF RETURN ISSUES</u>

Q. DO YOU AGREE THAT VARIOUS STATE UTILITY COMMISSIONS PROVIDE FOR ALLOWED RATES OF RETURN THAT REFLECT VARIOUS INCENTIVES AND DISINCENTIVES, BUT THAT THESE WOULD LIKELY NOT APPLY TO THE COMPANY?

A. No, I do not. The Company should be allowed a higher than average return reflecting various incentives, such as the fact that the Company is well-run and has historically been able to consolidate troubled nearby water systems with existing Company water systems. Water system consolidation has been encouraged by ADEQ and the Commission over many years. Apache Junction, Bisbee, Sierra Vista, Coolidge, Casa Grande, Sedona, and Valley Vista are examples of the many water systems that the Company consolidated into one larger system, in some cases virtually "over night," to resolve lost or failing water supplies.

Q. DO YOU AGREE THAT THE COMPANY SHARES THE SAME FINANCIAL OR INVESTMENT RISK AS THE SIX WATER/WASTEWATER COMPANIES STAFF RELIES ON IN ITS COST OF CAPITAL ANALYSIS?

A. No, I do not. The Company's risk is greater than any of these six companies for many reasons. One significant reason is that these six companies are not affected to the same degree by the new arsenic MCL. The problem of arsenic is greatest in the Southwestern United States and the Company must construct a large number of treatment facilities in numerous water systems over the next thirty months, estimated at a cost of approximately $30 million.

During the next 3 budget years, the Company will have to severely limit new construction or replacement projects due to the financial needs and efforts to complete arsenic treatment projects by January 23, 2006. This will delay other needed improvements, such as additional back-up water supplies, which may be needed by existing water systems and those impacted by the current drought. Replacement water mains may be delayed as well, due to budgetary and labor constraints, a predicament the Staff should be keenly aware of in light of the State's current budget woes. Radon gas, more stringent radionuclide maximum contaminant levels, water system vulnerability, disinfection byproducts and other upcoming federal regulations also pose additional financial risks since the Company will need to allocate or employ additional personnel and financial resources to comply with these new requirements.

Thus, it is readily apparent that the Company is bearing significant and unique risks that should be considered in setting the appropriate rate of return.

Q. DO YOU AGREE WITH RUCO THAT THE SAN MANUEL WATER SYSTEM HAS A SECURE SOURCE OF WATER NOW AND IN THE FUTURE?

A. No, I do not and this is another example of risk that has been ignored. *See* Direct Testimony of Timothy Coley, at 37, ls. 4-5. Although the Company has purchased its entire water supply for its San Manuel water system from BHP (formerly Magma Copper), the current agreement provides for termination of water service after a short notification time period. Although BHP may sell or lease its water production facilities to the Company in the event of a cancellation of its water service contract, there is no certainty that this would occur. This fact, coupled with the financial uncertainty of the mining industry, make the reliability of San Manuel's water supply questionable.

In addition, all of BHP's wells are located along the San Pedro River and are subject to challenge by the Gila River Indian Community ("GRIC") and other Globe Equity 59 right holders. Neither BHP nor the Company has received a waiver or settlement with the GRIC on the San Pedro and water supplies may also be subject to the current adjudication process. In summary, Mr. Coley's statements concerning the stability or security of the Company's water supplies for San Manuel are exaggerated and inaccurate and the insecurity and instability of San Manuel's water supplies increases the level of the Company's operational and financial risk.

VII. MISCELLANEOUS ISSUES

Q. ARE THERE ANY OTHER MATTERS YOU WISH TO ADDRESS?

A. Yes, the Company also objects to RUCO's recommendation that it be required to file a rate case within 3 years of a decision in this matter. *See* Rigsby Direct at 32, ls. 14-19. The Company already anticipates filing a rate case using test year 2006 or 2007 due to the impact of wellhead treatment costs associated with the new arsenic MCL, as well as the likely increase in other operating expenses. Thus, there is no basis for requiring the Company to file a rate case within 3 years, as RUCO contends.

Nevertheless, to address RUCO's concerns about variable O&M expenses related to the PCG's provision of replacement water to the Company, the Company would be willing to establish a PCG water adjustment mechanism to account for any increase or decrease in the cost of water, depending upon the quantity of water delivered by the PCG to the Company in any one year. If Staff and RUCO agree, the Company will prepare an exhibit detailing such an adjustment mechanism.

Q. DO YOU AGREE WITH RUCO'S POSITION CONCERNING RATE CONSOLIDATION FOR THE COMPANY'S APACHE JUNCTION AND SUPERIOR WATER SYSTEMS?

A. No, I do not agree with RUCO's position for the same reasons that I disagree with Staff's opposition to consolidated rates. Rate consolidation for Apache Junction and Superior should be approved for the reasons I stated earlier.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY IN THIS MATTER?

A. Yes, except to add that the Company does not waive its right to challenge any provision or recommendation not specifically addressed in rebuttal testimony.

EXHIBITS

AWWA Government Affairs

Water Conservation and Water Utility Programs

Approved June 28, 1995. To Be Published in *AWWA Mainstream*

Water conservation can be defined as practices, techniques, and technologies that improve the efficiency of water use. Increased efficiency expands the use of the water resource, freeing up water supplies for other uses, such as population growth, new industry, and environmental conservation.

Water conservation is often equated with temporary restrictions on customer water use. Although water restrictions can be a useful emergency tool for drought management or service disruptions, water conservation programs emphasize lasting day-to-day improvements in water use efficiency.

The Role of Water Conservation

Community water supply management requires balancing the development of adequate water supplies with the needs of the utility's customers. Traditionally, water utilities have focused primarily on developing additional supplies to satisfy increasing demands associated with population growth and economic development. Increasingly, however, water utilities throughout the United States are recognizing that water conservation programs can reduce current and future water demands to the benefit of the customer, the utility, and the environment.

The increasing efforts in water conservation, often called demand-side management, are spurred by a number of factors: growing competition for limited supplies, increasing costs and difficulties in developing new supplies, optimization of existing facilities, delay or reduction of capital investments in capacity expansion, and growing public support for the conservation of limited natural resources and adequate water supplies to preserve environmental integrity.

The focus of any supply strategy is to satisfy customer water needs in the most cost- effective and efficient manner, minimizing any adverse environmental impact and preserving the quality of life. Although conservation is sometimes an alternative to developing additional supplies, it is more often one of several complementary supply strategies for a utility. A conservation strategy, like any supply strategy, is part of a utility's overall planning and part of the integrated resource planning to ensure that all important community objectives and environmental goals are considered.

Water conservation in the broad sense is a key element in the day-to-day management of the modern water utility. Sound management includes the following basic water conservation practices:

- reduction of unaccounted-for water through universal metering and accounting of water use, routine meter testing and repair, and distribution system leak detection and repair;
- cost-of-service - based water rates; and
- public information and education programs to promote water conservation and to assist residential and commercial customers with conservation practices.

Beyond these fundamental conservation practices, effective water conservation programs are tailored to the needs and priorities of each community and recognize local and regional water demand characteristics and water supply availability.

Water Savings and Reliability

Conserved water can be considered a reliable water source. Great strides have been made over the past decade in evaluating and documenting the effectiveness of various conservation programs. Today there is a body of knowledge on water conservation, gained from the experiences of utilities, that provides a relatively high degree of confidence in the reliability and predictability of various water conservation measures. Some water planners feel, however, that the predictability and permanence of conservation measures have not been proven to the same degree as traditional supply measures.

The reliability of conserved water depends on accurate estimates of potential savings, expected benefits, and costs. Careful analysis and planning is a prerequisite to major utility investments in conservation programs. Reliability concerns also underscore the ongoing need for utilities to monitor and document the effectiveness of their conservation programs, just as they do water supplies and facilities.

Long-term conservation programs can affect short-term demand management practices. Reductions in water demands from long-term conservation programs and reductions from short-term demand management measures can overlap. Customers who have installed retrofit devices under long-term conservation programs may have less ability or willingness to further conserve.

In the event of water shortages, agencies with broad-based water conservation programs are able to mitigate short-term and long-term effects better than those without a conservation program.

Financial Aspects of Conservation

Conservation programs typically involve up-front costs, including revenue losses. The full benefits of conservation are realized only after all savings have materialized. However, reduced water sales because of conservation often develop slowly in small increments that can be accommodated in periodic rate adjustments.

Over the long-term, conservation can decrease a utility's need for new capital facilities for supply acquisition, treatment, storage, pumping, and distribution. It may also reduce the costs of operating those facilities. Deferring investment in such facilities or reducing their size can provide significant cost savings. In areas experiencing population growth, conservation can provide additional capacity to accommodate growth, resulting in a larger customer base over which to spread future capital costs. Water rates may be lower with conservation than without.

Water conservation can affect wastewater collection and treatment systems. Reduced hydraulic loadings can improve treatment performance in terms of effluent quality and reduced operating costs. Reducing wastewater flows through conservation can result in cost savings by deferring the need to enlarge wastewater treatment facilities.

Rates. The first goal of any rate structure is to generate sufficient revenues to maintain efficient and reliable utility operations, and the second is fairness in the allocation of utility service costs. Generally, it is possible to satisfy both of these goals in a rate structure that encourages water conservation or penalizes excessive water use.

Conservation-oriented water rate structures by themselves do not constitute an effective water conservation program. Rate structures work best as a conservation tool when coupled with a sustained customer education program. Customer education is important to establish and maintain the link between customer behaviors and their water bill. Utility customers require practical information about water-conserving practices and technologies. Participation in other water conservation programs, such as plumbing-fixture retrofit and replacement programs, can also be enhanced by rate incentives and customer education. Finally, public acceptance of rate structure changes is often enhanced if customers understand the need for and benefits of water conservation.

Arizona Corporation Commission
WORKING GROUP REPORTS

Attachment C

Proposed Policy For Water System Tiered Rate Design

Pricing/rate design is the Commission's primary means of encouraging conservation. The Commission can do this by implementing inverted block rates, i.e., tiered rates. Tiered rates may not be appropriate in all circumstances. Staff will consider the appropriateness of an inverted three-tiered commodity rate structure for all water company rate cases, and if appropriate, will recommend such a tiered rate structure to encourage conservation. The tiers should be designed in a manner that customers who conserve will recognize cost savings, while high water users will pay a greater portion of the costs that increased usage places on the water system. Criteria for evaluating the appropriateness and/or type of tiered rate structure on a case-by-case basis shall include, but not be limited to, the following:

1. Number of service connections on the system.
2. Number of high usage customers on the system.
3. Gallons of average water usage per connection per month.
4. Gallons of median water usage per connection per month.
5. Source of supply.

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ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

REBUTTAL TESTIMONY & EXHIBITS

OF

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Attorneys for Arizona Water Company

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS EASTERN GROUP AND FOR CERTAIN RELATED APPROVALS.	Docket No. W-01445A-02-0619

REBUTTAL TESTIMONY OF SHERYL L. HUBBARD

I. INTRODUCTION

Q. WHAT IS YOUR NAME, EMPLOYER AND OCCUPATION?

A. My name is Sheryl L. Hubbard. I am employed by Arizona Water Company (the "Company") as Manager of Rates and Regulatory Accounting.

Q. ARE YOU THE SAME SHERYL L. HUBBARD THAT PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS MATTER?

A. Yes, I am.

II. OVERVIEW, PURPOSE AND EXTENT OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to certain direct testimony submitted by the Arizona Corporation Commission's Utilities Division Staff ("Staff") and the Residential Utility Consumer Office ("RUCO") in this rate proceeding. Specifically, I will present the Company's rebuttal position with respect to several elements of rate base including plant in service, accumulated depreciation, post test year plant additions, working capital allowance, deferred Central Arizona Project ("CAP") charges, and the Phoenix Office and Meter Shop allocations of plant-related items. In addition, I will address a number of items related to net operating income such as the revenue annualization, purchased power expenses, the Company's Purchased Power Adjustment Mechanism ("PPAM"), the Company's Purchased Water Adjustment Mechanism ("PWAM"), amortization of deferred CAP charges, water testing expenses, rate case expenses, and amortization of Contributions in Aid of Construction.

I also wish to note that, to the extent that Company witnesses rebut recommendations by Staff or RUCO regarding the Pinal Creek Group ("PCG") settlement that affect rebuttal schedules I have prepared for the Miami system, an explanation of those will also be incorporated into my testimony.

Q. SO YOUR TESTIMONY IN THIS PROCEEDING INCORPORATES RECOMMENDATIONS OF OTHER COMPANY WITNESSES?

A. Yes, it does. My testimony in this proceeding incorporates recommendations sponsored by the Company's President William M. Garfield, as well as by Vice-Presidents Ralph J. Kennedy and Michael J. Whitehead.

Q. ARE YOU SPONSORING ANY OF THE COMPANY'S REBUTTAL EXHIBITS AND SCHEDULES?

A. Yes, I am sponsoring the following exhibits, all of which are attached to this testimony:

Exhibit SLH-R1 Original Cost Rate Base-Net Plant

Exhibit SLH-R2 Original Cost Rate Base

Exhibit SLH-R3 Copy of letter from SRP dated 10/18/02

Exhibit SLH-R4 Analysis of PPAMs and PWAMs

Exhibit SLH-R5 Copy of Staff Policy on CAP Cost Recovery

Exhibit SLH-R6 Staff Response to AWC's Data Request No. 5.1

Exhibit SLH-R7 Staff Response to AWC's Data Request No. 6.1

Q. PLEASE SUMMARIZE THE COMPANY'S APPLICATION FOR RATE RELIEF IN THIS PROCEEDING.

A. The Company's application for a rate increase for its Eastern Group systems was filed on August 14, 2002. At the time the filing was prepared, the most recent calendar year for which audited financial statements were available was 2001. To make the actual 2001 test year ("TY2001") more representative of the period when new rates would be in effect for the Eastern Group, 2001 account balances and results of operations were annualized and normalized based on known and measurable changes. The Company's goal was then and remains now, the presentation of a level of operating income that reflects the operating results that will be realized when new rates authorized in this proceeding go into effect. In connection therewith, the Company included in adjusted test year plant an appropriate amount of its plant investment dedicated to the adjusted test year customers as needed to ensure that a fair value determination can be computed and fair and reasonable rates could be developed.

Q. WHEN ARE THE NEW RATES AUTHORIZED IN THIS PROCEEDING ANTICIPATED TO GO INTO EFFECT?

A. Currently we anticipate a Commission decision by the end of January 2004 meaning new rates should go into effect for February of 2004.

III. USE OF UNADJUSTED HISTORICAL YEAR

Q. IS IT SOUND RATEMAKING TO USE AN UNADJUSTED HISTORICAL TEST YEAR TO DETERMINE FUTURE RATES?

A. No, it is not. Determination of the test year may be the most significant single factor in the ratemaking process. The test period must be representative of the period when the rates will be charged and an assessment of how the period to be used compares to the period when the rates will be charged is mandatory. Unless an historical period's results of operation are adjusted to recognize changing conditions, the rates so determined cannot be fair and reasonable. Even in stable economic times, historic data typically requires restatement for actual occurrences not expected to reoccur or for events that are expected to occur but did not exist (in whole or in part) in the historical unadjusted test year.

These adjustments, normalizing to restate an historical period for abnormal conditions, annualizing to reflect an annual level of revenue or expense for items included for a partial year that should be either increased or eliminated, out-of-period adjustments to adjust for items not properly reflected in the period, reclassification of items to add or remove items for purposes of rate recovery and adjusting for known and measurable changes in events or conditions that will affect future cost or revenue levels, must be considered and taken into account. Absent such adjustments, the rates determined will be distorted, either too low or too high, and will not be fair or reasonable.

Q. DOESN'T RUCO RECOMMEND THAT THE COMMISSION SET RATES BASED ON AN UNADJUSTED HISTORICAL TEST PERIOD?

A. Strictly speaking, RUCO clearly wishes to have the Commission set rates for the Eastern Group based on an unadjusted test year. *See, generally,* Direct testimony of William A. Rigsby and Direct testimony of Timothy J. Coley. However, having unsuccessfully advanced this same position in other ratemaking proceedings, including the Company's recent Northern Group rate case, RUCO now seeks, in essence, to change the test year used in this proceeding from a 2001 adjusted test year to an unadjusted 2002 test year.

Q. WHAT IS WRONG WITH RUCO'S POSITION?

A. To begin with trying to use 2002 as the test year in this proceeding violates the definition of test year in R14-2-103A.p. Moreover, it is inappropriate to use operating results that have not been analyzed to determine if 2002 is a representative period for basing future rates. This problem is exacerbated by the limited time allowed for the Company to prepare rebuttal testimony in this proceeding, a time frame in which it is impossible for Arizona Water to alter the test year and then determine specific deficiencies that exist in using an unadjusted 2002 historical period. Therefore, we urge the Commission to again reject RUCO's position and to utilize an adjusted 2001 test year to determine the Eastern Group's rates in this proceeding.

IV. RATE BASE

A. Plant In Service

Q. DOES THE COMPANY AGREE WITH STAFF'S PROPOSED PLANT IN SERVICE FOR THE SYSTEMS IN THE EASTERN GROUP?

A. No, although Staff and the Company do not appear to be far apart. Staff's calculations of Plant in Service for each system in the Eastern Group reflect Staff's erroneous removal of all of the actual, test year plant in service balances associated with the Phoenix Office and Meter Shop plant. The effect of this removal is an understatement in the Eastern Group's Rate Base of $1,615,233. Exhibit SLH-R1 sets forth the appropriate adjusted test year balances for the Eastern Group's Gross Plant in Service. Line 1, Gross Plant in Service, column (d) Rebuttal Adjusted TY, shows the Company's rebuttal calculation of Gross Plant In Service, which includes actual revenue neutral post-test year plant additions, to be $82,717,891. The Phoenix Office Allocation and Meter Shop Allocation, including the applicable revenue-neutral post-test year plant additions should be $1,758,733 and $38,139, as shown on lines 2 and 3 column (d), respectively. Thus, the total Gross Plant in Service for the Eastern Group should be $84,514,764. Stated simply, if Staff's recommended Gross Plant In Service for the Eastern Group of $82,899,530 is adjusted for the exclusion of the Phoenix Office and Meter Shop test year plant of $1,615,233, Staff-revised Plant in Service is $84,514,764, which the Company would accept as an appropriate amount for Gross Plant in Service. Exhibit SLH-R1 consists of nine pages setting forth the net plant recommendation for each of the individual Eastern Group systems.

B. Accumulated Depreciation

Q. STAFF IS RECOMMENDING AN ADJUSTMENT TO THE ACCUMULATED DEPRECIATION BALANCE TO REFLECT AN ADDITIONAL FULL-YEAR DEPRECIATION ON THE ADJUSTED TEST YEAR PLANT IN SERVICE. DOES THE COMPANY AGREE WITH THIS METHODOLOGY?

A. No, and the Staff provides no rationale for increasing the accumulated depreciation balance. *See* Direct Testimony of Ronald E. Ludders ("Ludders Direct") at 21. Staff ignores the adoption in this proceeding of a 2001 test year showing a deterioration in earnings, the very circumstances that prompted the filing of a rate application. The Company's pro forma adjustment to plant in service for the non-revenue producing post-test year plant is merely an attempt to partially reduce the effects of regulatory lag in obtaining rate relief to allow the Company an opportunity to earn a fair rate of return on investments to serve test year end customers. It is the Company's intention that the post-test year plant additions be treated as if (pro forma) the investment were in service at the end of the test year. Therefore, accumulated depreciation should not be adjusted for any more than the additional depreciation expense that will be computed on the year-end balance including the pro forma post-test year plant additions.

In contrast, if an additional year of depreciation is computed and used to reduce the Company's rate base, the Company's opportunity to earn a fair rate of return on its recognized investments is further hindered. While the Company is awaiting a final decision, the deterioration in earnings continues.

Q. BUT ISN'T THE COMPANY RECOMMENDING A PRO FORMA ADJUSTMENT TO DEPRECIATION EXPENSE?

A. Yes, but this is different than Staff's (and RUCO's) recommended adjustments to accumulated depreciation. The purpose of the Company's pro forma adjustment to depreciation expense is to recognize the known and measurable change in test year 2001 operating cost levels that will result from additional depreciation on plant not previously included in the depreciation calculation or in the Company's rates.

Jurisdictions that recognize an additional adjustment to the accumulated depreciation balance concurrently include an equal amount of depreciation expense in the calculation of operating expenses. In other words, the pro forma adjustment to annualize the depreciation expense may also be used to increase the accumulated depreciation balance in the rate base calculation. The Company's calculations conform to this conventional treatment. The pro forma depreciation expense adjustments and the adjustment to the accumulated depreciation are, in fact, identical.

Staff's pro forma depreciation expense and associated adjustment to the accumulated depreciation are not. To illustrate, the Staff's pro forma depreciation expense adjustment for Apache Junction is a reduction of $212,006 while the adjustment to accumulated depreciation for Apache Junction is an increase of $1,210,940 ($1,307,339-$96,399). The appropriate accumulated depreciation balance of $18,157,533, which recognizes the Staff's recommended levels of post-test year plant additions is shown at line 5, column (d) on Exhibit SLH-R1.

Q. ARE THERE OTHER DEFICIENCIES IN STAFF'S PROPOSED ADJUSTMENTS TO THE ACCUMULATED DEPRECIATION BALANCE?

A. Yes. Upon closer examination of the supporting working papers provided by Staff, Staff's calculation of the accumulated depreciation balance of $19,835,625 (total Eastern Group) has <u>not</u> been adjusted for the reduction in depreciation expense that occurs when plant is retired. This adjustment is necessary to properly reflect the half-year convention that the Company uses to depreciate plant additions in the year the plant is placed in service. The same half-year convention applies in the year that the property is retired. Staff's calculations encompass the period from the last Arizona Water Company rate decision for the Eastern Group in 1991 through December 31, 2002. As such, the adjustment is overstated by the effect of the half-year conventions on all retirements of plant over a twelve-year period.

Q. HAVE YOU PREPARED A SCHEDULE COMPARING THE STAFF'S RECOMMENDED ACCUMULATED DEPRECIATION TO THE COMPANY'S?

A. Yes. Exhibit SLH-R1 is a summary of Net Plant as set forth in the Company's application compared to Staff's recommendation for Net Plant. This schedule shows the Company's revised or, more accurately, rebuttal position for accumulated depreciation to recognize the affects of the changes in post-test year plant additions that the Company is adopting in its rebuttal presentation. The Staff's proposed level of Accumulated Depreciation of $19,835,625 contains several errors as discussed above, and should not be relied upon. As such, the Company is recommending an Accumulated Depreciation balance for the adjusted test year of $18,157,533 as shown on Exhibit SLH-R1, line 5, column (d).

Q. WHAT AMOUNT OF NET PLANT IS THE COMPANY RECOMMENDING IN ITS REBUTTAL FILING?

A. The Company is recommending Net Plant for its Eastern Group systems of $66,357,231 as shown on Exhibit SLH-R1, line 8, column (d).

C. Post Test Year Plant Additions

Q. HAS THE COMPANY REVIEWED THE STAFF'S RECOMMENDATIONS CONCERNING POST TEST YEAR PLANT ADDITIONS?

A. Yes. Mr. Whitehead explains the Company's response to the Staff's recommended Post Test Year Plant Additions. *See* Exhibit MJW-R1, attached to the Rebuttal

Testimony of Michael J. Whitehead.

D. Working Capital Allowance

Q. DO YOU AGREE WITH STAFF'S USE OF A 592 LAG DAY FACTOR IN CALCULATING THE CASH WORKING CAPITAL COMPONENT RELATED TO PROPERTY TAXES?

A. No, we do not. The lead/lag method of computing the cash working capital component of rate base requires a calculation of the lead days (prepayments) or lag days (accruals) that exist between the time an expense is recorded and the payment of such expenses. Although it is generally accepted that property taxes have a payment lag, Staff has exaggerated the actual lag 2.8 times. While the Department of Revenue recently modified the methodology for determining property taxes for water utilities in Arizona; it did not revise the billing or payment requirements, including the timing of the payments. The property taxes that the Company accrues in January through June of any given year are payable in November of that same year, while the property taxes that are accrued in July through December are payable in May of the following year.

It follows that the extended lag should be an average of 212 days versus Staff's 592 lag days. 212 lag days represents the same number of lag days adopted by this Commission for property taxes in the Company's Northern Group case utilizing a 1999 test year. Decision No. 64282 (December 28, 2001). RUCO witnesses have also computed the lag days for property taxes at 212 days. *See, e.g.*, Schedule WAR-7 page 2 of 4. I would also note that this is the same number of lag days that APS used in its recently filed rate application. *See* Testimony of Laura L. Rockenberger (Docket No. E-01345A-00437) at attachment LLR-3. Staff has clearly computed the property tax lag incorrectly for working capital purposes. Adopting the Company's lag day calculation for working capital purposes results in an adjustment of $1,264,932 to the Staff's working capital allowance of ($1,054,873) on a total Eastern Group basis.

Q. HAS THE COMPANY IDENTIFIED OTHER CONCERNS WITH THE CALCULATION OF THE CASH WORKING CAPITAL ALLOWANCE PROPOSED BY STAFF?

A. Yes. In his direct testimony, Mr. Ludders discusses five adjustments to the Company's analysis that resulted from Staff's analysis of the Company's lead-lag analysis. Ludders Direct at 9, ls. 11-18. Of the five adjustments identified, only two adjustments are consistent with the working papers provided in support of the Staff's working capital calculation: item (3) "Staff recognized interest expense" and (5) "Staff used a method that eliminates the mismatch between the dollar amount included in the dollar-day revenue and dollar-day expense lag amounts by comparing revenue lag days directly to payment lag days"..

The other three identified adjustments to the Company's analysis are not consistent with the working papers Staff provided. More specifically, (1) "Staff used expense amounts and expense lag days for each individual system" implies that the Company's working capital calculation did not use an individual system approach; (2) "Staff removed depreciation expense and deferred income taxes from the calculation of expense lag days" implies that the Company's calculation of expense lag days included depreciation expense and deferred income taxes; and (4) "Staff incorporated its adjustments to operating expenses." In each instance Staff's inferences are in error.

Schedule B-6, page 3 of 3 of the Company's 2002 Rate Hearing Exhibit specifically has the notation "N/A" (denoting not applicable) in the column labeled Average (Lead)Lag Days calculating the expense lag days for depreciation expense and deferred income taxes. In reference to operating expenses, Staff did not incorporate its adjustments to operating expenses as stated in their witness' direct testimony. The operating expenses used by Staff are the same as are included in the Company's working capital calculation. Thus, Staff's calculation of the working capital allowance is unreliable and cannot form the basis for determining an appropriate working capital allowance in this proceeding.

Q. STAFF HAS ADJUSTED THE COMPANY'S WORKING CAPITAL ALLOWANCE TO REFLECT A LAG ASSOCIATED WITH THE PAYMENT OF INTEREST. IF STAFF'S RECOMMENDATION IS ADOPTED, WHAT IS THE EFFECT ON THE COMPANY'S REBUTTAL PRESENTATION?

A. Using the Company's Rate Base presented on Exhibit SLH-R2, the interest payment lag would be calculated by computing the applicable system's interest expense (rate base times the weighted cost of debt) and applying the Staff's lag days factor of .25 (91.25 lag days divided by 365 days) to compute the necessary reduction in the Company's working capital allowance. On an Eastern Group basis, the reduction in the Company's requested working capital allowance is approximately $255,000.

E. Deferred Central Arizona Project Charges

Q. HAS THE COMPANY REVIEWED THE STAFF'S PROPOSED TREATMENT OF DEFERRED CENTRAL ARIZONA PROJECT COSTS?

A. Yes. Staff is recommending continued inclusion in rate base of the unamortized balance of the $60,000 deferred CAP charges authorized in Decision No. 58120 (December 23, 1992) and the net balance of the Company's actual deferred Cap M&I charges incurred from 1993 through December 31, 2002. Although Staff used the Company's original deferred CAP balance of $704,903 in the calculation of its recommended revenue requirement, the actual 2002 balance as discussed in

Staff' testimony is $691,522 ($46,315 + $645,207).

Q. WHAT AMORTIZATION PERIOD IS THE STAFF RECOMMENDING FOR RECOVERY OF THE DEFERRED CAP M&I CHARGES?

A. Frankly, it is unclear, even though we have reviewed Staff's direct filing, whether Staff is proposing to amortize the deferred CAP M&I charges over a period of 32 or 34 years.

Q. DOES THE COMPANY AGREE WITH A 32 OR 34-YEAR AMORTIZATION PERIOD FOR RECOVERY OF THE DEFERRED CAP M&I CHARGES?

A. Absolutely not. The basis of Staff's recommendation is that the deferred CAP M&I charges are an asset with some future benefit. This is just not the case. The M&I charges are a lease payment, if you will, for the use of the Central Arizona Project canal system for the annual delivery of up to 6,000 AF of Colorado River water for the Apache Junction system for the period of the CAP contract. The M&I charges were deferred by Arizona Water until such time as its CAP allocation was being fully utilized. Arizona Water has been using a portion of its annual allocation for potable consumption since prior to entry of Decision 58120 without cost recovery of the CAP M&I charges.

Q. HAS THE COMMISSION ADDRESSED THE RECOVERY OF DEFERRED CAP M&I CHARGES ?

A. Yes. As I discussed in my direct testimony (at 13-15), Commission Decision No. 62993 (November 3, 2000) directed Staff to develop a policy statement regarding recovery of costs related to CAP. In that policy statement, the Staff identified criteria required to demonstrate compliance and obtain CAP cost recovery. The policy statement is attached as Exhibit SLH-R5.

Q. IS ARIZONA WATER COMPANY ABLE TO DEMONSTRATE

COMPLIANCE WITH THESE IDENTIFIED CRITERIA?

A. Yes. Again, as shown in my direct testimony (at 13-15), Arizona Water has demonstrated compliance with each of the criteria identified in the Staff's policy statement regarding recovery of CAP costs.

Q. HAS THIS COMMISSION ADDRESSED THE RECOVERY OF DEFERRED CAP M&I CHARGES FOR OTHER WATER UTILITIES?

A. Yes. In Decision No. 62293 (February 1, 2000), the Commission addressed the recovery of deferred CAP M&I charges for Sun City Water Company and Sun City West Utilities Company, now operational districts of Arizona-American Water Company. In that case, following a determination that the CAP water was "used and useful", the deferred CAP charges were amortized over the period that the charges had accumulated, a period of five years, which resulted in a 60-month amortization period.

Q. FOLLOWING THE SAME APPROACH, WHAT WOULD BE THE APPROPRIATE AMORTIZATION PERIOD FOR ARIZONA WATER?

A. In 1993, Arizona Water began deferring the CAP M&I charges that comprise the $645,207 balance at December 31, 2002. The test year in this case has been adjusted for the known and measurable deferred CAP M&I charges through December 31, 2002. Following the Commission's reasoning in Decision No. 62293, the amortization period should be no longer than the period over which the M&I charges were billed, which in the Company's case would be nine years.

Q. IS THE COMPANY MODIFYING ITS REQUEST TO AMORTIZE THE DEFERRED CAP M&I CHARGES FROM ITS ORIGINAL REQUEST FOR A THREE-YEAR AMORTIZATION?

A. No. The Company set forth its rationale for requesting a three-year amortization in its direct testimony (*See* Hubbard Direct at 28) and is not convinced that other amortization periods are more reasonable given Arizona Water's individual circumstances.

Q. WHAT ABOUT RUCO'S RECOMMENDATIONS REGARDING THE AMORTIZATION PERIOD FOR DEFERRED CAP M&I CHARGES?

A. RUCO, consistent with its use of an unadjusted 2002 historical test year, is recommending the amortization of the deferred CAP M&I charges balance at December 31, 2002 over a period not less than ten years. Although the recommended ten-year amortization period is reasonable, the amount that RUCO recommends be amortized is entirely unsupported by the evidence. RUCO recommends that the Company be limited to the $645,207 deferred as of December 31, 2002, which permanently eliminates the recovery of the CAP M&I charges deferred in 2003 and the period in 2004 prior to the time the new rates become effective. Thus, RUCO's position is punitive and confiscatory. The charges are a legitimate cost of providing water to Arizona Water's customers and as such should not be disallowed.

F. Phoenix Office And Meter Shop Allocations Of Plant-Related Items

Q. PLEASE DISCUSS THE STAFF'S TREATMENT OF PHOENIX OFFICE AND METER SHOP ALLOCATIONS OF PLANT-RELATED ITEM.

A. In general, the Staff's presentation begins with the Company's filed positions. Recommended levels of rate base elements such as plant, accumulated depreciation, and working capital were determined and the Company's requested amounts were adjusted to the Staff recommended level. In the Company's presentation, test year rate base for the Phoenix Office and Meter Shop were computed and subsequently allocated to the individual systems as two separate line items labeled Phoenix Office Allocation and Meter Shop Allocation set forth on the Company's Schedule B-1.

The Post Test Year Plant Additions associated with the Phoenix Office and Meter Shop allocations, on the other hand, were included with the Post Test Year Plant Additions Pro Forma adjustment of each individual system presented on the Company's Schedule B-2. When the Staff computed its recommended Post Test Year Plant Additions associated with the Phoenix Office and the Meter Shop, it, apparently inadvertently, adjusted the test year level of plant for the Phoenix Office Allocation and the Meter Shop Allocation, effectively eliminating the test year plant in service for the Eastern Group allocation of the Phoenix Office and Meter Shop plant. The effect of this error is an understatement of plant in service of $1,615,234 as discussed above (at 5).

Q. TO INCORPORATE ALL OF THE FOREGOING RATE BASE-RELATED ADJUSTMENTS, HAVE YOU PREPARED AN EXHIBIT OF THE

COMPANY'S REQUESTED RATE BASE IN ITS REBUTTAL PRESENTATION?

A. Yes, Exhibit SLH-R2 is a nine-page schedule that summarizes the Company's Original Cost Rate Base in this rebuttal presentation for each of the Eastern Group systems. The Eastern Group Original Cost Rate Base requested is $39,002,876.

V. <u>NET OPERATING INCOME</u>

A. Revenue Annualization

Q. DOES THE COMPANY AGREE WITH THE STAFF'S RECOMMENDED ADJUSTMENT TO THE COMPANY'S REVENUE ANNUALIZATION PRO FORMA ADJUSTMENT?

A. The Company has reviewed the basis of the Staff's recommended change in the Revenue Annualization Pro Forma adjustment and is of the opinion that the Company's adjustment as originally calculated more accurately represents the increase in revenues necessary to adjust the test year operating results to a year end level of customers. The Company computed average revenue per customer using only the 5/8-inch meter size because the majority of the growth in the Eastern Group systems for the test year occurred in the 5/8-inch meter group, as shown on the following table.

Customer Class	Increase in # of Customers	% of Total
Residential	588	98%
Commercial	7	1%
Industrial	1	.2%
Fire Sprinkler	7	1%
Other	-2	-.3%
Total	601	100%

By computing and applying an average revenue per customer using all customer classes to the test year end increase in customers, as Staff is proposing, the revenue annualization is overstated because increases that will not occur are reflected in the proposed adjustment. Staff has applied to 588 customers $160 of additional revenue which will not materialize, an overstatement in revenues for the Eastern Group of no less than $94,080 (588 X ($510-350)).

B. Purchased Power Adjustment Clause

Q. DOES THE COMPANY AGREE WITH STAFF'S RECOMMENDED ELIMINATION OF THE COMPANY'S PURCHASED POWER ADJUSTMENT MECHANISM?

A. No, we do not agree. There are several reasons to continue the purchased power adjustment mechanism ("PPAM") for Arizona Water Company at this time. For one thing, the Company purchases electricity to pump water from several electric providers, including, among others, Arizona Public Service Company ("APS"), Salt River Project ("SRP"), and Navopache Electric Cooperative ("NEC"). SRP and NEC have adjustor mechanisms for their power costs that allow them to unilaterally adjust the charge to Arizona Water for electric power. See Exhibit SLH-R3.

If viewed in isolation, i.e., on an individual system basis, the PPAM factors approved in the Company's latest PPAM filing may seem insignificant. However, the effect is more significant over longer time periods and on a total Company basis, as shown on Exhibit SLH-R4. Although Staff complains about the level of work required, without any real explanation of the alleged burden, the truth is, the Company minimizes the number of filings by aggregating all systems affected by a utility's power change in a single application, thus performing the majority of the work necessary to document the requested changes for Staff to review as part of the

PPAM filing. Staff seeks to trivialize the PPAMs approved in 2003 by reflecting the net change requested. *See* Ludders Direct at 10. What is more important to note is the fact that PPAMs are currently providing reduced purchased power costs to customers of approximately $63,000 annually in the Eastern Group, and $198,000 annually on a company-wide basis. Without the PPAMs, these reductions would not have been passed on to the Company's customers except following the establishment of new rates in a rate case.

Moreover, a PPAM provides benefits for both the customer and the Company. Since 1996, under the terms of several settlement agreements, APS has been reducing its rates annually. Through the PPAM, Arizona Water has been able to pass those reductions to its customers. In addition, it is the Company's understanding that APS is currently before the Commission seeking to implement a PPAM in its rates and charges to allow it to better reflect the market price of power in its retail rates. And, we further understand APS recently filed a request for a rate increase with the Commission. Without a PPAM, both customers and the Company will be unable to reflect rate changes whether the change is an increase or a decrease, absent filing a complete rate case filing. This is neither fair to the Company or ratepayers and makes little sense from a standpoint of administrative and regulatory efficiency.

In summary, therefore, with the electric power industry still in a transitional stage, power costs, one of the Company's most substantial operating costs will not remain at their current levels clearly making it the wrong time to eliminate the PPAM.

Q. BUT ISN'T IT STAFF'S POSITION THAT ARIZONA WATER COMPANY IS THE ONLY WATER PROVIDER STILL USING THIS ADJUSTOR?

A. That is not a persuasive reason at all. Per Staff's Response to the Company's Data

Request No. 6.2, copy attached as Exhibit SLH-R7, Bella Vista Water is the only water provider other than Arizona Water that had a PPAM in the last ten years. Bella Vista's PPAM was eliminated in 1999 but it was eliminated pursuant to a settlement agreement, and not without reservations. The more relevant language from the settlement is:

> The elimination of the PPAM in this proceeding shall not be used by the Arizona Corporation Commission Staff, the Arizona Corporation Commission or RUCO to support the denial of the PPAM in the future. (Exhibit A to Decision No. 61730, June 4, 1999).

A more relevant criterion to analyze would be how many Commission-regulated, users of electric energy still use an adjustor mechanism to pass changes in electricity costs to their customers. This analysis would demonstrate that the ability to adjust one's rates to cover changes in costs to purchase power is a necessary element of rate design. Another relevant criterion Staff should have analyzed is how many providers of electric energy have the ability to change their retail rates without a full and complete rate case due to the use of adjustor mechanisms, significantly affecting the costs to purchase power by larger retail users such as Arizona Water.

Q. HAS THE COMPANY PERFORMED SUCH AN ANALYSIS?

A. Yes, and the result of the Company's analysis is that at least fifty percent of the regulated electric utilities listed on the Commission's website still have purchased power adjustment mechanisms in their filed tariffs. These entities have the ability to adjust their retail electric rates to reflect changes in purchased power costs on a monthly basis without Commission approval. An example is provided at page 3 of Exhibit SLH-R3. Of the seven Commission-regulated gas utilities, all appear to have adjustor mechanisms in their tariffs, again, with the ability to adjust their retail rates on a monthly basis without Commission approval. It was also determined that there has been no concerted attempt by Staff to eliminate those adjustor mechanisms from the rate design of those entities. The Company's PPAM should not be eliminated either. Electric and gas adjustor mechanisms do not require prior Commission approval before being placed into effect. The Commission may consider modifying the mechanism to eliminate the requirement for Commission approval of the changes in the adjustor factors.

C. Purchased Water Adjustment Mechanism

Q. STAFF ALSO RECOMMENDS ELIMINATION OF THE PURCHASED WATER ADJUSTOR MECHANISM ALTOGETHER. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. No, the Company does not agree that the purchased water adjustment mechanism ("PWAM") should be eliminated. Mr. Ludders discusses the Company's purchased water adjustment mechanism for the Ajo, San Manuel and Superior systems in his direct testimony. *See* Ludders Direct at 11, ls. 12-21. Of course, as a starting point, any discussion of eliminating the adjustor mechanism for the Company's Ajo system is outside this Eastern Group rate case because the Ajo system is part of the Company's Western Group systems.

Regarding the recommendation to eliminate the PWAM for the San Manuel and Superior systems, the Company opposes Staff's recommendation. In the San Manuel system, during the test year, purchased water expense was twenty-nine percent (29%) of that systems' operations and maintenance expenses. The last two increases by BHP increased the cost of purchased water from $.57 to $1.12, a ninety-six percent (96%) increase. The price that Arizona Water pays to purchase water for its San Manuel system is set by BHP and outside the control of the Company or the Commission because BHP in not a public utility. Even when the Company attempted to obtain a legal remedy to obtain a more reasonable price for the purchased water, BHP prevailed. As a consequence, eliminating the PWAM from the San Manuel system would expose the Company to increased risk from large, uncontrollable operating expense increases.

Assuming that the recommended two-step consolidation of the Superior and Apache Junction systems is approved, the Superior PWAM would be eliminated in the next rate proceeding when a common commodity cost is developed for both systems.

Q. HAS THE COMMISSION ADDRESSED THE QUESTION OF MODIFYING THE PURCHASED POWER AND PURCHASED WATER ADJUSTOR MECHANISMS IN PAST ARIZONA WATER COMPANY RATE MAKING DOCKETS?

A. Yes. In Commission Decision No. 58120 (December 23, 1992), the Commission rejected Staff's recommended change in the thresholds for obtaining an adjustment in the PPAM and PWAM, stating:

> If purchased power and/or water costs are trending upward, gradually recognizing those increasing costs through incremental rate adjustments sends a more appropriate price signal to users and receives greater customer acceptance than the less frequent, but far larger, rate increases contemplated in Staff's proposal. If purchased power and/or water costs are trending downward, Staff's proposal would delay the refund owing to customers. We believe these customer interests are best served by retaining the existing thresholds.

See Decision No. 58120 at 30, l. 20 through 31 at l. 1. This rationale has not changed and the Company urges the Commission to maintain the Company's existing adjustor mechanisms.

D. Central Arizona Project Cost Amortization

Q. ON JUNE 19, 2003, CAWCD ADOPTED THE FINAL 2004 WATER RATE SCHEDULE THAT CONTAINS CAP CAPITAL AND DELIVERY

CHARGES FOR 2004. SHOULD THESE CAP CAPITAL AND DELIVERY CHARGES BE INCORPORATED IN THE COMPANY'S OPERATING EXPENSES IN THIS PROCEEDING?

A. Yes. To properly compute operating results for the period that the rates resulting from this proceeding will be in effect, known and measurable changes in the M&I charge and CAP delivery charges must be incorporated. The M&I charge of $74 per acre foot ("AF") adopted on June 19, 2003 by the CAWCD compares to the $66 per AF proposed by the Company and accepted by Staff in its filing. Since the $74 per AF rate is a known and measurable change, an adjustment should be made to the Company's operating expenses. The amount of the adjustment due to the change in the M&I rate per AF is an additional increase of $16,520 (2065 AF X ($74-$66)) in the M&I charges over that already reflected in the Company's and Staff's proposals.

The delivery charge was also revised to $32 per AF from the test year level of $43 per AF. The effect of this concurrent known and measurable change, recognized by both Staff and RUCO, neither of which picked up the change in the M&I charge, is a decrease of $22,715 (2065 AF X ($32-$43)) in the delivery charges for water delivered to the Mesa Treatment Plant. The effect of recognizing these known and measurable changes in CAP purchased water expense is a net decrease of $6,195 ($16,520-$22,715) to the Staff's recommended level of $152,532 shown on Schedule REL-13 for Apache Junction.

Q. SCHEDULE REL-13 FOR APACHE JUNCTION SUMMARIZES THE PURCHASED WATER EXPENSES FROM THE COMPANY'S FILING AND STAFF'S ADJUSTED LEVEL. ARE THE AMOUNTS SHOWN CORRECT?

A. The total adjusted test year 2001 purchased water expense of $1,003,040 shown on the Company's Schedule C-1, line 2, for Apache Junction includes two pro forma adjustments. One is a pro forma adjustment to annualize purchased water costs of $166,225 (*See* Schedule C-2, page 6 of 36, line 7) and the second is a pro forma adjustment to annualize expenses for year-end customers in the amount of $31,604 (*See* Schedule C-2 page 5 of 36) totaling the $197,829 referred to in the testimony of Staff's witness Ronald E. Ludders on page 24. Staff has eliminated the $31,604 in error on its Schedule REL-13. Staff, on its Schedule REL-15, correctly addresses this portion of the Company's purchased water costs, but the effect of Staff's error is an understatement of its recommended purchased water expenses of $31,604.

E. Water Testing Expenses

Q. IS STAFF'S RECOMMENDED ADJUSTMENT TO THE COMPANY'S PROPOSED WATER TESTING EXPENSES TO REMOVE CHARGES FOR TESTING FOR RADIO-CHEMICALS APPROPRIATE?

A. Staff's Response to the Company's Data Request No. 5.1, copy attached as Exhibit SLH-R6, states that the costs for testing for radio-chemicals for new wells are more appropriately capitalized and included in the development costs of the well. Based upon this response, the Company will not oppose the Staff's recommended level of water testing costs which exclude testing for radio-chemicals for new wells which is not covered by the Monitoring Assistance Program ("MAP").

F. Rate Case Expense

Q. DOES THE COMPANY AGREE WITH STAFF'S RECOMMENDATIONS CONCERNING RATE CASE EXPENSE?

A. The Company strongly objects to Staff's recommendation to limit rate case expense to some arbitrary level estimated by Staff. It is somewhat ironic that Staff relies on the "known and measurable" concept when it reduced the Company's revenue requirement but proposes the use of "their estimates" at times when they wish to reduce the recovery of legitimate actual, known and measurable expenses. Staff's recommendation does not purport to use the amount of "known and measurable" rate case expense as of September 15 with an estimate of only the remaining costs. Instead, the basis of Staff's recommended level of rate case expense is premised, in large part, on a comparison of rate case expenses incurred in the Company's 1990 rate case versus the Northern Group's 1999 rate case and the estimate for this proceeding. In reaching this result, Staff ignores the significant differences between the 1990 and 1999 case and asks the Commission to assume they are using a valid comparison. Staff's comparison doesn't even rise to the level of "apples and oranges"; it is more of a "fruit and vegetable" comparison. In the 1990 rate case, which included all eighteen systems of Arizona Water Company, an in-house preparation and defense was utilized. In other words, there was no outside counsel or cost of capital witness. The Company's experience in that proceeding, coupled with the implementation of time clock rules with extremely short time periods for preparation of rebuttal and rejoinder testimony and the increasingly litigious nature of rate cases, particularly the increased reliance on formal data requests (over 200 served on the Company by Staff alone in this docket), it was determined that additional resources were necessary for processing future rate requests.

Ironically, outside services were retained to assist in preparing both the cost of capital and the legal defense of the Company's 1999 rate request and the Commission adopted the Company's proposed level of rate case expense.

In any event, it follows that a comparison to the situation more than a decade ago is not a valid comparison. Indeed, it is the Company's position that an estimate of the level of rate case expense must be evaluated on its individual merits and a determination of the appropriate amount of recovery to be authorized based thereon. The Staff has a data request, REL 25-2, setting forth an estimate of the cost of outside services through the final disposition of the rate case that will be updated on September 15, 2003. It is the Company's intention to update the current estimate of $274,550 at that time with actual "known and measurable" expenses including an allocation of the actual legal fees incurred in the Arsenic Cost Recovery Mechanism ("ACRM") proceeding, Phase Two of the Northern Group rate proceeding, which proceeding will benefit both the Northern and Eastern Group customers. In addition, the Company will provide a further updated estimate as soon as the billings for the hearings have been received.

Q. IS STAFF CORRECT IN ITS ASSUMPTION THAT HALF OF THE COMPANY'S ATTORNEYS' FEES ASSOCIATED WITH THIS RATE CASE WERE INCURRED AS OF APRIL 30, 2003?

A. No. Specifically, Staff estimates that half of the attorney fees were incurred as of April 30, 2003 because Staff characterized this date as the half way point of the rate case. *See* Ludders Direct at 13, ls. 10-27. However, as of April 30, 2003, the Company had not seen any of the other parties' filings, including Staff's hundred's of pages of direct testimony and schedules, had not yet conducted any discovery, and had not begun preparing its rebuttal filing. Moreover, no party has yet to submit a surrebuttal or rejoinder filing, not a single day of hearing has yet taken place and no post-hearing briefing has occurred. Frankly, as of April 30, 2003, something less than a third of the rate case activities had taken place and the bulk of work by attorneys (analyzing other parties' filings, preparing rebuttal and rejoinder, hearing and briefing) had not yet commenced.

In sum, Staff's claim that the Company has completed half this rate case, at least so far as its attorneys are involved, is without merit. Certainly a more sound basis for establishing the reasonableness of the Company's known and measurable rate case expenses must be offered before there is any basis to reduce the amount of the Company's requested rate case expense.

Q. **DOES THE COMPANY AGREE WITH STAFF'S RECOMMENDED 5-YEAR AMORTIZATION OF RATE CASE EXPENSE?**

A. No we do not. Instead, the Company continues to believe that an amortization period of three years is appropriate. There are many factors impacting the time a utility seeks rate relief and in volatile times such as we are experiencing with fluctuating costs of capital, increased need for capital investments and potential infrastructure improvements, and uncertainty of economic conditions, a three-year amortization could most likely match the period of time before Arizona Water must seek additional rate relief. Therefore, the Company maintains its request for a three-year amortization.

G. Additional CIAC Amortization

Q. **IS THE STAFF PROPOSING AN ADJUSTMENT TO THE COMPANY'S CONTRIBUTIONS IN AID OF CONSTRUCTION ("CIAC") AMORTIZATION?**

A. It appears that the Staff is calculating the amortization of CIAC at a composite depreciation rate and adjusting the Company's depreciation expense. *See* Ludders Direct at 32, ls. 2-5. As far as the Company can discern, a 2.34 percent rate has been applied to the test year-end balance of gross contributions for the Eastern Group of $7,850,910. This calculation is apparently intended to reflect the new level of CIAC amortizations that the Company should incur utilizing the component depreciation rates. If this is the intended purpose, the annual amortization should have been compared to the amount included in the Company's presentation, which is $185,965 on a total Eastern Group basis. In addition, a composite rate should have been developed using the annual depreciation associated with the plant accounts that include contributions. Those accounts are the Transmission and Distribution Mains, Fire Sprinkler Taps, Services, Meters, and Hydrants. A composite rate for the Eastern Group's contributed plant accounts is more appropriately 2.00% for this proceeding. Applying this figure to the CIAC balance of $7,850,910 results in a total Eastern Group amortization of $157,018 contrasted to the test year level of $185,965, an adjustment increasing the depreciation expense by $28,947 versus the Staff's adjustment, which reduces depreciation expense by $191,417 on a total Eastern Group Basis. Although not included in the Staff's direct filing, this adjustment to depreciation expense, for consistency purposes, should also be reflected as an adjustment to the CIAC balance reflected in Rate Base.

H. PCG Settlement-Net Operating Income Effects

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENTS TO REBUT STAFF'S RECOMMENDATION CONCERNING TREATMENT OF THE PCG SETTLEMENT?

A. To begin with, as explained by Mr. Garfield and quantified by Mr. Kennedy, Staff has completely ignored all of the benefits of the settlement already obtained for ratepayers in the Miami system. The Company correctly accounted for the settlement payment as Mr. Kennedy described in his testimony. To adopt the Company's rebuttal position as developed thoroughly in the Rebuttal Testimony of Mr. Garfield and Mr. Kennedy, a reversal of all PCG-related adjustments is necessary.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does, except that I wish to note that my silence on any issue raised or recommendation made by Staff or RUCO should not be taken as the Company's acceptance of such issue or recommendation.

EXHIBITS

Arizona Water Company
ORIGINAL COST RATE BASE - NET PLANT
END OF TEST YEAR 2001

			Eastern Group		
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	86,270,323	82,717,891	0	82,717,891
2.	Phoenix Office Allocation	1,639,085	177,640	1,581,093	1,758,733
3.	Meter Shop Allocation	34,141	3,999	34,140	38,139
4.	Total Gross Plant In Service	87,943,549	82,899,530	1,615,233	84,514,764
5.	less: Accumulated Depreciation	(18,321,740)	(19,835,625)	1,678,091	(18,157,533)
6.	Net Plant In Service	69,621,810	63,063,906	3,293,325	66,357,231
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	69,621,810	63,063,906	3,293,325	66,357,231

Arizona Water Company
ORIGINAL COST RATE BASE - NET PLANT
END OF TEST YEAR 2001

			Apache Junction			
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)	
1.	Gross Plant In Service	55,226,791	51,814,226	0	51,814,226	(a)
2.	Phoenix Office Allocation	852,453	86,619	822,293	908,912	
3.	Meter Shop Allocation	17,756	1,960	17,756	19,716	
4.	Total Gross Plant In Service	56,097,000	51,902,805	840,049	52,742,854	
5.	less: Accumulated Depreciation	(8,791,705)	(9,892,252)	1,299,493	(8,592,759)	
6.	Net Plant In Service	47,305,295	42,010,553	2,139,542	44,150,095	
7.	Construction Work In Progress	0	0	0	0	
8.	Total Net Plant	47,305,295	42,010,553	2,139,542	44,150,095	

(a) - $704,903 removed from Gross Plant in Service for Unamortized CAP to be shown as separate item on Rate Base Schedule.

Arizona Water Company
ORIGINAL COST RATE BASE - NET PLANT
END OF TEST YEAR 2001

Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Bisbee Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	7,433,939	7,613,913	0	7,613,913
2.	Phoenix Office Allocation	189,951	19,301	183,230	202,531
3.	Meter Shop Allocation	3,956	436	3,956	4,392
4.	Total Gross Plant In Service	7,627,846	7,633,650	187,186	7,820,837
5.	less: Accumulated Depreciation	(3,099,049)	(3,228,015)	116,066	(3,111,949)
6.	Net Plant In Service	4,528,797	4,405,635	303,253	4,708,888
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	4,528,797	4,405,635	303,253	4,708,888

Arizona Water Company
ORIGINAL COST RATE BASE - NET PLANT
END OF TEST YEAR 2001

		Miami			
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	6,837,666	6,770,808	(0)	6,770,808
2.	Phoenix Office Allocation	193,170	19,629	186,336	205,965
3.	Meter Shop Allocation	4,024	444	4,024	4,468
4.	Total Gross Plant In Service	7,034,860	6,790,881	190,359	6,981,240
5.	less: Accumulated Depreciation	(1,713,977)	(1,745,153)	23,278	(1,721,875)
6.	Net Plant In Service	5,320,883	5,045,728	213,637	5,259,365
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	5,320,883	5,045,728	213,637	5,259,365

Arizona Water Company
ORIGINAL COST RATE BASE - NET PLANT
END OF TEST YEAR 2001

Oracle

Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	5,179,022	5,064,631	(0)	5,064,631
2.	Phoenix Office Allocation	93,008	9,452	89,717	99,169
3.	Meter Shop Allocation	1,937	214	1,937	2,151
4.	Total Gross Plant In Service	5,273,967	5,074,297	91,654	5,165,951
5.	less: Accumulated Depreciation	(1,468,545)	(1,570,314)	97,821	(1,472,493)
6.	Net Plant In Service	3,805,422	3,503,983	189,475	3,693,458
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	3,805,422	3,503,983	189,475	3,693,458

Arizona Water Company
ORIGINAL COST RATE BASE - NET PLANT
END OF TEST YEAR 2001

		San Manuel			
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	1,554,600	1,514,841	(0)	1,514,841
2.	Phoenix Office Allocation	79,057	8,033	76,260	84,293
3.	Meter Shop Allocation	1,647	182	1,647	1,829
4.	Total Gross Plant In Service	1,635,304	1,523,056	77,907	1,600,962
5.	less: Accumulated Depreciation	(736,074)	(708,955)	(27,313)	(736,268)
6.	Net Plant In Service	899,231	814,102	50,593	864,694
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	899,231	814,102	50,593	864,694

Arizona Water Company
ORIGINAL COST RATE BASE - NET PLANT
END OF TEST YEAR 2001

			Sierra Vista		
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	5,282,359	5,219,293	0	5,219,293
2.	Phoenix Office Allocation	130,569	13,267	125,949	139,216
3.	Meter Shop Allocation	2,720	300	2,720	3,020
4.	Total Gross Plant In Service	5,415,648	5,232,860	128,669	5,361,529
5.	less: Accumulated Depreciation	(1,406,900)	(1,499,622)	89,077	(1,410,545)
6.	Net Plant In Service	4,008,748	3,733,238	217,746	3,950,984
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	4,008,748	3,733,238	217,746	3,950,984

Arizona Water Company
ORIGINAL COST RATE BASE - NET PLANT
END OF TEST YEAR 2001

			Superior		
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	4,327,525	4,299,052	0	4,299,052
2.	Phoenix Office Allocation	89,788	9,123	86,612	95,735
3.	Meter Shop Allocation	1,870	207	1,870	2,077
4.	Total Gross Plant In Service	4,419,183	4,308,382	88,482	4,396,864
5.	less: Accumulated Depreciation	(986,086)	(1,066,976)	76,079	(990,897)
6.	Net Plant In Service	3,433,097	3,241,406	164,561	3,405,967
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	3,433,097	3,241,406	164,561	3,405,967

Arizona Water Company
ORIGINAL COST RATE BASE - NET PLANT
END OF TEST YEAR 2001

			Winkelman		
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	428,421	421,127	0	421,127
2.	Phoenix Office Allocation	11,089	12,216	10,697	22,913
3.	Meter Shop Allocation	231	256	231	487
4.	Total Gross Plant In Service	439,741	433,599	10,928	444,527
5.	less: Accumulated Depreciation	(119,404)	(124,338)	3,590	(120,748)
6.	Net Plant In Service	320,337	309,261	14,519	323,780
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	320,337	309,261	14,519	323,780

Arizona Water Company
ORIGINAL COST RATE BASE
END OF TEST YEAR 2001

			Eastern Group		
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	86,270,323	82,717,891	0	82,717,891
2.	Phoenix Office Allocation	1,639,085	177,640	1,581,093	1,758,733
3.	Meter Shop Allocation	34,141	3,999	34,140	38,139
4.	Total Gross Plant In Service	87,943,549	82,899,530	1,615,233	84,514,764
5.	less: Accumulated Depreciation	(18,321,740)	(19,835,625)	1,678,091	(18,157,533)
6.	Net Plant In Service	69,621,810	63,063,906	3,293,325	66,357,231
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	69,621,810	63,063,906	3,293,325	66,357,231
9.	Less: Customers' Advances for Construction	(17,232,663)	(17,232,663)	0	(17,232,663)
10.	Contributions in Aid of Construction				
11.	Gross	(7,850,910)	(7,850,910)	0	(7,850,910)
12	Accumulated Amortization	968,440	968,440	(28,947)	939,493
13.	Net Contributions In Aid Of Construction	(24,115,133)	(24,115,133)	(28,947)	(24,144,080)
14.	Deferred Income Tax	(4,825,667)	(4,825,667)	0	(4,825,667)
15.	Deferred CAP (Net)	0	684,785	6,737	691,522
16.	Add: Total Working Capital Allowance (b)	923,870	(1,054,873)	1,978,743	923,870
17.	Total Rate Base Components & Adjustments	41,604,880	33,753,018	5,249,858	39,002,876
18.	[redacted]				
19.	[redacted]				

Arizona Water Company
ORIGINAL COST RATE BASE
END OF TEST YEAR 2001

		Apache Junction				
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)	
1.	Gross Plant In Service	55,226,791	51,814,226	0	51,814,226	(a)
2.	Phoenix Office Allocation	852,453	86,619	822,293	908,912	
3.	Meter Shop Allocation	17,756	1,960	17,756	19,716	
4.	Total Gross Plant In Service	56,097,000	51,902,805	840,049	52,742,854	
5.	less: Accumulated Depreciation	(8,791,705)	(9,892,252)	1,299,493	(8,592,759)	
6.	Net Plant In Service	47,305,295	42,010,553	2,139,542	44,150,095	
7.	Construction Work In Progress	0	0	0	0	
8.	Total Net Plant	47,305,295	42,010,553	2,139,542	44,150,095	
9.	Less: Customers' Advances for Construction	(15,443,377)	(15,443,377)	0	(15,443,377)	
10.	Contributions in Aid of Construction					
11.	Gross	(6,228,486)	(6,228,486)	0	(6,228,486)	
12	Accumulated Amortization	713,806	713,806	(21,017)	692,789	
13.	Net Contributions In Aid Of Construction	(20,958,057)	(20,958,057)	(21,017)	(20,979,074)	
14.	Deferred Income Tax	(2,699,309)	(2,699,309)	0	(2,699,309)	
15.	Deferred CAP (Net)	0	684,785	6,737	691,522	(a)
16.	Add: Total Working Capital Allowance (b)	559,087	(691,907)	1,250,994	559,087	
17.	Total Rate Base Components & Adjustments	24,207,016	18,346,065	3,376,255	21,722,320	

(a) - $704,903 removed from Gross Plant in Service for Unamortized CAP to be shown as separate item on Rate Base Schedule.

Arizona Water Company
ORIGINAL COST RATE BASE
END OF TEST YEAR 2001

			Bisbee		
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	7,433,939	7,613,913	0	7,613,913
2.	Phoenix Office Allocation	189,951	19,301	183,230	202,531
3.	Meter Shop Allocation	3,956	436	3,956	4,392
4.	Total Gross Plant In Service	7,627,846	7,633,650	187,186	7,820,837
5.	less: Accumulated Depreciation	(3,099,049)	(3,228,015)	116,066	(3,111,949)
6.	Net Plant In Service	4,528,797	4,405,635	303,253	4,708,888
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	4,528,797	4,405,635	303,253	4,708,888
9.	Less: Customers' Advances for Construction	(190,083)	(190,083)	0	(190,083)
10.	Contributions in Aid of Construction				
11.	Gross	(372,133)	(372,133)	0	(372,133)
12	Accumulated Amortization	55,613	55,613	(1,209)	54,404
13.	Net Contributions In Aid Of Construction	(506,603)	(506,603)	(1,209)	(507,812)
14.	Deferred Income Tax	(423,066)	(423,066)	0	(423,066)
15.	Deferred CAP (Net)	0	0	0	0
16.	Add: Total Working Capital Allowance (b)	100,985	(50,285)	151,270	100,985
17.	Total Rate Base Components & Adjustments	3,700,113	3,425,681	453,313	3,878,995

Arizona Water Company
ORIGINAL COST RATE BASE
END OF TEST YEAR 2001

		Miami			
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	6,837,666	6,770,808	(0)	6,770,808
2.	Phoenix Office Allocation	193,170	19,629	186,336	205,965
3.	Meter Shop Allocation	4,024	444	4,024	4,468
4.	Total Gross Plant In Service	7,034,860	6,790,881	190,359	6,981,240
5.	less: Accumulated Depreciation	(1,713,977)	(1,745,153)	23,278	(1,721,875)
6.	Net Plant In Service	5,320,883	5,045,728	213,637	5,259,365
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	5,320,883	5,045,728	213,637	5,259,365
9.	Less: Customers' Advances for Construction	(109,428)	(109,428)	0	(109,428)
10.	Contributions in Aid of Construction				
11.	Gross	(188,394)	(188,394)	0	(188,394)
12	Accumulated Amortization	32,086	32,086	(1,061)	31,025
13.	Net Contributions In Aid Of Construction	(265,736)	(265,736)	(1,061)	(266,797)
14.	Deferred Income Tax	(566,719)	(566,719)	0	(566,719)
15.	Deferred CAP (Net)	0	0	0	0
16.	Add: Total Working Capital Allowance (b)	81,768	(122,661)	204,429	81,768
17.	Total Rate Base Components & Adjustments	4,570,196	4,090,612	417,005	4,507,617
18.	[redacted]				
19.	[redacted]				

Arizona Water Company
ORIGINAL COST RATE BASE
END OF TEST YEAR 2001

Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Oracle Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	5,179,022	5,064,631	(0)	5,064,631
2.	Phoenix Office Allocation	93,008	9,452	89,717	99,169
3.	Meter Shop Allocation	1,937	214	1,937	2,151
4.	Total Gross Plant In Service	5,273,967	5,074,297	91,654	5,165,951
5.	less: Accumulated Depreciation	(1,468,545)	(1,570,314)	97,821	(1,472,493)
6.	Net Plant In Service	3,805,422	3,503,983	189,475	3,693,458
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	3,805,422	3,503,983	189,475	3,693,458
9.	Less: Customers' Advances for Construction	(473,356)	(473,356)	0	(473,356)
10.	Contributions in Aid of Construction				
11.	Gross	(258,151)	(258,151)	0	(258,151)
12	Accumulated Amortization	37,740	37,740	(1,225)	36,515
13.	Net Contributions In Aid Of Construction	(693,767)	(693,767)	(1,225)	(694,992)
14.	Deferred Income Tax	(344,341)	(344,341)	0	(344,341)
15.	Deferred CAP (Net)	0	0	0	0
16.	Add: Total Working Capital Allowance (b)	52,086	(50,607)	102,693	52,086
17.	Total Rate Base Components & Adjustments	2,819,400	2,415,268	290,943	2,706,211

Arizona Water Company
ORIGINAL COST RATE BASE
END OF TEST YEAR 2001

			San Manuel		
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	1,554,600	1,514,841	(0)	1,514,841
2.	Phoenix Office Allocation	79,057	8,033	76,260	84,293
3.	Meter Shop Allocation	1,647	182	1,647	1,829
4.	Total Gross Plant In Service	1,635,304	1,523,056	77,907	1,600,962
5.	less: Accumulated Depreciation	(736,074)	(708,955)	(27,313)	(736,268)
6.	Net Plant In Service	899,231	814,102	50,593	864,694
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	899,231	814,102	50,593	864,694
9.	Less: Customers' Advances for Construction	(23,194)	(23,194)	0	(23,194)
10.	Contributions in Aid of Construction				
11.	Gross	(20,375)	(20,375)	0	(20,375)
12	Accumulated Amortization	2,990	2,990	46	3,036
13.	Net Contributions In Aid Of Construction	(40,579)	(40,579)	46	(40,534)
14.	Deferred Income Tax	(93,372)	(93,372)	0	(93,372)
15.	Deferred CAP (Net)	0	0	0	0
16.	Add: Total Working Capital Allowance (b)	28,714	(38,700)	67,414	28,714
17.	Total Rate Base Components & Adjustments	793,994	641,451	118,053	759,503

Arizona Water Company
ORIGINAL COST RATE BASE
END OF TEST YEAR 2001

Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Sierra Vista Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	5,282,359	5,219,293	0	5,219,293
2.	Phoenix Office Allocation	130,569	13,267	125,949	139,216
3.	Meter Shop Allocation	2,720	300	2,720	3,020
4.	Total Gross Plant In Service	5,415,648	5,232,860	128,669	5,361,529
5.	less: Accumulated Depreciation	(1,406,900)	(1,499,622)	89,077	(1,410,545)
6.	Net Plant In Service	4,008,748	3,733,238	217,746	3,950,984
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	4,008,748	3,733,238	217,746	3,950,984
9.	Less: Customers' Advances for Construction	(587,611)	(587,611)	0	(587,611)
10.	Contributions in Aid of Construction				
11.	Gross	(699,448)	(699,448)	0	(699,448)
12	Accumulated Amortization	113,980	113,980	(4,045)	109,935
13.	Net Contributions In Aid Of Construction	(1,173,079)	(1,173,079)	(4,045)	(1,177,124)
14.	Deferred Income Tax	(331,421)	(331,421)	0	(331,421)
15.	Deferred CAP (Net)	0	0	0	0
16.	Add: Total Working Capital Allowance (b)	70,439	(28,293)	98,732	70,439
17.	Total Rate Base Components & Adjustments	2,574,687	2,200,445	312,433	2,512,878

Arizona Water Company
ORIGINAL COST RATE BASE
END OF TEST YEAR 2001

Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Superior Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	4,327,525	4,299,052	0	4,299,052
2.	Phoenix Office Allocation	89,788	9,123	86,612	95,735
3.	Meter Shop Allocation	1,870	207	1,870	2,077
4.	Total Gross Plant In Service	4,419,183	4,308,382	88,482	4,396,864
5.	less: Accumulated Depreciation	(986,086)	(1,066,976)	76,079	(990,897)
6.	Net Plant In Service	3,433,097	3,241,406	164,561	3,405,967
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	3,433,097	3,241,406	164,561	3,405,967
9.	Less: Customers' Advances for Construction	(384,759)	(384,759)	0	(384,759)
10.	Contributions in Aid of Construction				
11.	Gross	(82,088)	(82,088)	0	(82,088)
12	Accumulated Amortization	11,961	11,961	(423)	11,538
13.	Net Contributions In Aid Of Construction	(454,886)	(454,886)	(423)	(455,309)
14.	Deferred Income Tax	(332,521)	(332,521)	0	(332,521)
15.	Deferred CAP (Net)	0	0	0	0
16.	Add: Total Working Capital Allowance (b)	27,886	(53,426)	81,312	27,886
17.	Total Rate Base Components & Adjustments	2,673,576	2,400,573	245,450	2,646,023

Arizona Water Company
ORIGINAL COST RATE BASE
END OF TEST YEAR 2001

			Winkelman		
Line No.	Description	AWC's Adjusted TY (As Filed) (a)	Staff's Adjusted TY (b)	Proposed Rebuttal Adjustments (c)	Rebuttal Adjusted TY (d)
1.	Gross Plant In Service	428,421	421,127	0	421,127
2.	Phoenix Office Allocation	11,089	12,216	10,697	22,913
3.	Meter Shop Allocation	231	256	231	487
4.	Total Gross Plant In Service	439,741	433,599	10,928	444,527
5.	less: Accumulated Depreciation	(119,404)	(124,338)	3,590	(120,748)
6.	Net Plant In Service	320,337	309,261	14,519	323,780
7.	Construction Work In Progress	0	0	0	0
8.	Total Net Plant	320,337	309,261	14,519	323,780
9.	Less: Customers' Advances for Construction	(20,855)	(20,855)	0	(20,855)
10.	Contributions in Aid of Construction				
11.	Gross	(1,835)	(1,835)	0	(1,835)
12	Accumulated Amortization	264	264	(11)	253
13.	Net Contributions In Aid Of Construction	(22,426)	(22,426)	(11)	(22,437)
14.	Deferred Income Tax	(34,918)	(34,918)	0	(34,918)
15.	Deferred CAP (Net)	0	0	0	0
16.	Add: Total Working Capital Allowance (b)	2,905	(18,994)	21,899	2,905
17.	Total Rate Base Components & Adjustments	265,898	232,923	36,406	269,329

CENTENNIAL SRP 1903-2003

P. O. Box 52025
Phoenix, Arizona 85072-2025

RECEIVED
OCT 22 2002
ARIZONA WATER COMPANY
PHOENIX - EXECUTIVE

October 18, 2002

Mr. Bill Garfield
Arizona Water Company
3805 N Black Canyon Hwy
Phoenix, AZ 85038-9006

Dear Bill,

SRP has incurred unanticipated fuel and purchased power costs in providing electricity to its retail customers during the first quarter of SRP's fiscal year (May 2002 through July 2002). These increased costs were precipitated by the purchase of power to replace generation units that have been curtailed or on outage. For example, SRP's hydro generation has been substantially reduced due to the drought, and certain local generating units have been on extended outage due to mechanical difficulties.

As a result, SRP's Board of Directors considered a management proposal to increase the Fuel and Purchased Power Adjustment Factor at a meeting held on Thursday, October 17, 2002. Management proposed establishing an adjustment factor of $0.00180/kWh applicable to all customer bills, and the Board agreed to this change.

This review of the Fuel and Purchased Power Adjustment Factor is in accordance with established procedures followed by the SRP Board of Directors and does not constitute a change to SRP's standard electric price plans. This change is effective with customer electric bills dated on or after November 1, 2002, concurrent with the implementation of winter base prices, which are substantially lower than summer base prices. As a result, we anticipate that most customers will see their bills decline over the winter billing season (November 2002 through April 2003).

Changes in the fuel and purchased power adjustment factor reflect solely actual fuel and purchased power costs, estimated future fuel and purchased power costs and the operational performance of generation units. The unanticipated fuel and purchased power costs are planned for collection over an 18-month period to minimize impacts on our customers.

While this change will affect your monthly electric bills, SRP also is undertaking measures to reduce fuel and other operating costs in the future. Further, SRP will continue to review fuel and purchased power costs on a quarterly basis and may propose to revise or eliminate the adjustment at a later date.

Even with this change, SRP's prices will continue to be among the lowest in Arizona and in the Southwest. If you have any questions, please contact your Account Manager, Mike G. Sullivan at 602.236.5708.

Sincerely,

Scott A. Trout

Scott A. Trout
Manager, Commercial Customer Services

Navopache Electric Cooperative Bills now Unbundled

The Arizona Corporation Commission has requested that electric utilities unbundle their bills. Unbundling is the breakdown of the bills into components of electric service and related service charges such as generation, meter reading and billing, etc. Navopache Electric Cooperative has opted to do this as of your February billing. Below you will find a layout of the different charges and descriptions relating to these charges.

Distribution Charges:

Fixed Monthly Charge
Metering Charge
Meter Reading Charge
Billing Charge
Electricity Charge
Environmental Surcharge
Public Benefits Charge
CTC (Stranded Cost)

Total Distribution Charges

Generation Charges:

Electricity Charge
Power Cost Adjustment

Total Generation Charges

Service & Other Charges:

Deposit Applied
Establishment Fee

Total Other Services

Previous Balance:
Payments Received:
Balance Forward:
Total Distribution Charges:
Total Generation Charges:
Total Services & Other Charges:
Taxes:

Definitions

Distribution Charges – Charges directly related to the delivery of electric service to residential or business users. The Distribution Charges are based on the monthly energy usage to pay costs to build and operate the system.

Fixed Monthly Charge – The Customer Service Charge. This charge varies depending on the type of service. Where it is necessary to extend or reinforce existing distribution facilities, the minimum monthly charge may be increased to assure adequate compensation for the added facilities.

Metering Charge, Meter Reading Charge and Billing Charge – These charges are for providing these functions each month for the membership.

Electricity Charge – The consumer rate for kWh distributed.

Environmental Surcharge – Is paid by all electric utility consumers. This fee goes to a fund to help develop renewable resources.

Public Benefits Charge – Adder to help offset the costs associated with Navopache programs designed to promote load management and mandated by the Arizona Corporation Commission.

CTC (Competitive Transition Adjustment Charge, also referred to as stranded costs) – Based on your monthly energy usage, this goes to pay some of the costs for investments in power plants that were made under regulation.

Generation Charges – Charges associated with generation.

Electricity Charge – Consumer rate for kWh generated

Power Cost Adjustment – Factored in when the purchased power cost is increased or decreased beyond the base purchase power cost for every kilowatt hour sold. This difference is then passed on to all classes of consumers. While it can fluctuate on a monthly basis, the Power Cost Adjustment fctor has been a credit to consumers for quite some time. It has been responsible for the especially low winter bills this season.

Service & Other Charges – The fees that fall under this category are miscellaneous energy charges such as: deposit (refunded or assessed); establishment fee; check reading fee; reconnect fee; meter test fee; etc.

The new billing will also show the previous balance, payments received and the balance forward. This additional information is a welcome change and will provide easier accounting for our members.

Arizona Water Company
Analysis of PPAMs and PWAMs

	M-Gallons Sold 2001	Conversion to 100-Gallons	Effective 07/01/2003		Effect on 2001 Test Year Levels		Total
			PPAM Rates	PWAM Rates	PPAM Rates	PWAM Rates	PPAM & PWAM
Apache Junction	2,283,704.4	22,837,044.0	(0.0010)	0.0000	(22,837.04)	0.00	(22,837.04)
Bisbee	299,129.8	2,991,298.0	(0.0070)	0.0000	(20,939.09)	0.00	(20,939.09)
Sierra Vista	345,613.6	3,456,136.0	0.0000	0.0000	0.00	0.00	0.00
Casa Grande	3,185,006.3	31,850,063.0	(0.0010)	0.0000	(31,850.06)	0.00	(31,850.06)
Stanfield	30,942.3	309,423.0	(0.0040)	0.0000	(1,237.69)	0.00	(1,237.69)
White Tank	185,738.8	1,857,388.0	(0.0040)	0.0000	(7,429.55)	0.00	(7,429.55)
Ajo	55,672.6	556,726.0	0.0000	0.0000	0.00	0.00	0.00
Coolidge	438,791.0	4,387,910.0	0.0000	0.0000	0.00	0.00	0.00
Lakeside	259,834.2	2,598,342.0	(0.0270)	0.0000	(70,155.23)	0.00	(70,155.23)
Overgaard	101,494.4	1,014,944.0	(0.0140)	0.0000	(14,209.22)	0.00	(14,209.22)
Miami	310,124.4	3,101,244.0	(0.0060)	0.0000	(18,607.46)	0.00	(18,607.46)
San Manuel	214,845.7	2,148,457.0	(0.0020)	0.0760	(4,296.91)	163,282.73	158,985.82
Oracle	106,216.5	1,062,165.0	0.0030	0.0000	3,186.50	0.00	3,186.50
Winkelman	49,612.5	496,125.0	(0.0010)	0.0000	(496.13)	0.00	(496.13)
Sedona	971,086.1	9,710,861.0	(0.0010)	0.0000	(9,710.86)	0.00	(9,710.86)
Pinewood	83,797.7	837,977.0	(0.0010)	0.0000	(837.98)	0.00	(837.98)
Rimrock	87,115.9	871,159.0	0.0000	0.0000	0.00	0.00	0.00
Superior	110,459.0	1,104,590.0	0.0010	0.0000	1,104.59	0.00	1,104.59
Total Company	9,119,185.2	91,191,852.0			(198,316.13)	163,282.73	(35,033.40)

Exhibit SLH-R5
Page 1 of 2

Arizona Corporation Commission
WORKING GROUP REPORTS

Attachment D

Proposed Policy for Central Arizona Project (CAP) Cost Recovery

The consensus of the CAP Working Group is that the Arizona Corporation Commission (Commission) should encourage water companies to retain their Central Arizona Project (CAP) water allocation. The purpose is to allow water companies to accomplish long term planning of their water resource needs for the benefit of their customers. The consensus of the group was that the Commission should accomplish this encouragement as follows:

1. A water company would be allowed to recover CAP costs if it could demonstrate that it needed the CAP allocation to properly serve its customers.
2. The water company must demonstrate that the need would occur by the year 2025.
3. The water company must demonstrate that it will actually be using a reasonable amount of its CAP allocation by 2025.
4. The water company must demonstrate that it will be using all of its CAP allocation by 2034.
5. "Use" will be those methods of using CAP water that are defined as "use" by the Arizona Department of Water Resources.
6. In order to obtain cost recovery, a water company must file a rate case and provide evidence demonstrating items 1 though 4 above.
7. At the time that cost recovery is approved for a water company, cost recovery will depend on how much of company's CAP allocation is actually being used -

    a. If none of the CAP allocation is actually being used, the company will be allowed to recover dollar for dollar its appropriate CAP expenses, without earning a rate of return. The cost recovery will be split between a charge in the commodity portion of the rate and a CAP Hook-up Fee. The charge in the commodity will be that amount needed to pay the M&I portion of the expense for that amount of CAP water equal to the amount of groundwater actually being used by the current customers. The CAP Hook-up Fee will be calculated as that portion needed to pay the remainder of the M&I charges. This is similar to the method used in the Vail Water Company rate case (Decision No. 62450). If the CAP Hook-up Fee is determined by the Commission to have to be excessive in order to recover all the CAP costs, the remainder should be deferred and collected later as the company grows and adds additional customers and/or the rate of growth increases to allow the collection of additional CAP Hook-up Fees.
    b. If only a portion of the CAP allotment is being used, cost recovery will be split. For that portion of the CAP allotment not being used, cost recovery will be allowed as explained above (#7a). For that portion of the CAP allotment actually being used, cost recovery will be as with any other used and useful item in a rate case, i.e., the plant needed will be included in rate base and earn a rate of return, while the M&I and OM&R expenses for

that portion of the CAP allotment will be recovered as any other expense.

c. When all the CAP allotment is being used, cost recovery will be as described in the second half above (#7b), i.e., just like any other plant and expense item that is used and useful.
d. For those water companies that have not obtained a specific accounting order from the Commission that details how CAP costs incurred up to this time would be treated and meet items 1 through 4 above, the actual amount of direct costs incurred (i.e., no rate of return or cost of money) should be recovered in rates by some method determined in a rate case, as long as such an allowance is not somehow improper (e.g., retroactive rate making, contrary to some mandatory accounting/rate making principle, etc.).

8. Within 5 years of obtaining approval for cost recovery of the CAP costs, the water company must submit a detailed engineering plan outlining how the water will be put to use.

9. If a water company that has obtained cost recovery from the Commission is not using its total CAP allotment by 2034, that portion not being used shall be sold. If a water company has recovered from ratepayers the cost for retaining that portion of the CAP allocation it sells, all net proceeds shall be refunded to ratepayers in a manner to be determined by the Commission at that time. Similarly, if a water company sells all or any portion of its CAP allocation after recovering from ratepayers the cost to retain the portion it sells, all net proceeds shall be refunded to ratepayers.

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**STAFF'S RESPONSES TO
ARIZONA WATER COMPANY'S
FIFTH SET OF DATA REQUESTS
ACC DOCKET NO. W-01445A-02-0619**

July 28, 2003

5.1 On page 10 of the Direct Testimony of Lyndon R. Hammon at line 23, it states that Staff's difference from the Company's *pro forma* expense is mainly due to ADEQ rule changes for the inclusion of radio-chemicals in the MAP program.

(a) What is ADEQ's requirement, if any, for testing for radio-chemicals on new wells?

(b) Are these tests included in the MAP tests?

(c) If not, has staff allowed testing costs for these required tests?

Response: See attached

(a) The ADEQ requirements are delineated in the Arizona Administrative Code, R-18-4-505.B.1., "Approval To Construct", which states:
"1. An application for Approval to Construct, including the following documents and data, shall be submitted to the Department:
(a) Detailed construction plans…
(b) Complete specifications…
(c) A design report…
(d) **Analyses of a proposed new source of water**…"

Sometimes this information is not available during the design stage (e.g., the well may be drilled but not equipped), and DEQ will make its construction approval conditional upon acceptable biological and chemical analyses. The "Approval Of Construction" (operational approval) will be given co-incident with DEQ's receipt of those analyses and inspection results.

(b) No. Initial testing is not performed by MAP and the initial testing cost is the responsibility of the water company. Subsequent testing is performed by MAP, if the water company qualifies by size.

(c) No. Staff would not normally recommend the inclusion of future prospective costs as an annual, recurring expense. This initial testing is a one time, non-recurring cost. Instead, Staff would recommend that this type of cost be

STAFF'S RESPONSES TO
ARIZONA WATER COMPANY'S
FIFTH SET OF DATA REQUESTS
ACC DOCKET NO. W-01445A-02-0619

July 28, 2003

capitalized and included in the development costs of the well, as construction plans, engineering specifications, and design reports, should be similarly treated.

Response by: Lyndon Hammon

STAFF'S RESPONSES TO ARIZONA WATER COMPANY'S SIXTH SET OF DATA REQUESTS ACC DOCKET NO. W-01445A-02-0619

July 31, 2003

6.1 On page 10 of the Direct Testimony of Ronald E. Ludders at line 18, Mr. Ludders testifies in reference to purchased power adjustor mechanisms that "[c]urrently, Arizona Water Company is the only water provider still using this adjustor."

a) Please identify all water companies that have had adjustor mechanisms in the past ten years.
b) In reference to a) above, provide the date or timeframe when the adjustor mechanisms were eliminated and a reference to the Commission Decision.
c) Please provide the names of any utilities regulated by the Arizona Corporation Commission that currently have purchased power adjustment mechanisms.
d) In reference to the response to c) above, has the Commission Staff made any recommendations in Staff reports or testimony to eliminate the purchased power adjustment mechanisms of any of the identified entities in the past five years?
e) If the answer to d) above is affirmative, please provide list of Company names, docket numbers and Commission decisions.

Response: Pursuant to Rule 33(c), Ariz.R.Civ.Pro., please be advised that the information sought is located in the most recent rate decisions for each company and in the current tariffs of each company. The most recent rate decisions are located in the Commission's docket control center, located at 1200 West Washington, Phoenix. The current tariffs are on file with the Commission's Tariff Administrator, who is located at the same address.

Response by: Claudio Fernandez for Ronald E. Ludders

Sheryl Hubbard

From: JSHAPIRO@FCLAW.COM
Sent: Friday, August 01, 2003 11:04 AM
To: Ralph Kennedy; RJKenndy@extremezone.com; Bob Geake; Sheryl Hubbard; Bill Garfield
Subject: FW: Arizona Water's 6th Set of Data Requests

FYI.

-----Original Message-----
From: Tim Sabo [mailto:TSabo@admin.cc.state.az.us]
Sent: Friday, August 01, 2003 10:54 AM
To: SHAPIRO, JAY
Subject: RE: Arizona Water's 6th Set of Data Requests

Regarding 6.1, the only one we are aware of is Bella Vista. Bella Vista had a Purchased Power Adjustor, which was eliminated in Decision 61730 (Jun 4, 1999). Regarding 6.2, the reclassification adjustment was done because the item was inventory, but was listed as an expense. I don't know if it was chemicals, or filters or what. Ron will be back on Monday, and if the Company needs the details, Mr. Kennedy or Ms. Hubbard can give him a call. The other part of the adjustment was to use actual 2002 expenses, rather than "pro forma" 2002 expenses.

>>> <JSHAPIRO@FCLAW.COM> 07/31/03 04:18PM >>>
Tim--we have reviewed the responses that were just provided to Arizona Water's 6th set of data requests and have two areas of concern.

First, with respect to 6.1, although the Company really should not be expected to gather the orders themselves given that Staff has repeatedly insisted that this and other utilities obtain publicly available information for Staff in response to data requests, at a minimum Staff must identity the names of the water companies requested in subsection (a).

Second, Staff's response to 6.2 seems to explain what the adjustment is, but not the basis, which is the focus of the question. Therefore, the answer is non responsive.

We would like revised answers by 2:00 p.m. Friday, August 1, 2003 in light of our rapidly approaching rebuttal deadline. Please let me know immediately if Staff will not provide these additional responses.

Jay

-----Original Message-----
From: Tim Sabo [mailto:TSabo@admin.cc.state.az.us]
Sent: Thursday, July 31, 2003 3:27 PM
To: SHAPIRO, JAY; JAMES, NORM
Subject: Arizona Water's 6th Set of Data Requests

Attached is Staff's response to Arizona Water's 6th Set of Data Requests.

Let me know if you have any questions.

The information contained in this message may be protected by the attorney-client privilege. Please immediately reply to the sender of this e-mail if you have received it in error, then delete it. Thank you.

For more information on Fennemore Craig, please visit us at http://www.fennemorecraig.com.

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ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

REBUTTAL TESTIMONY & EXHIBITS

OF

Ralph J. Kennedy

FENNEMORE CRAIG
A Professional Corporation
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Attorneys for Arizona Water Company

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS EASTERN GROUP AND FOR CERTAIN RELATED APPROVALS.	Docket No. W-01445A-02-0619

REBUTTAL TESTIMONY OF RALPH J. KENNEDY

Table of Contents

I. INTRODUCTION AND PURPOSE EXTENT OF TESTIMONY

Q. WHAT IS YOUR NAME, EMPLOYER AND OCCUPATION?

A. My name is Ralph J. Kennedy. I am employed by Arizona Water Company (the "Company") as Vice President and Treasurer.

Q. ARE YOU THE SAME RALPH J. KENNEDY THAT PREVIOUSLY PROVIDED DIRECT TESTIMONY ON THIS MATTER?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to certain direct testimony submitted by the Arizona Corporation Commission's Utilities Division Staff ("Staff") and the Residential Utility Consumer Office ("RUCO") in this rate proceeding. Specifically, I will address the proper ratemaking treatment for the funds received by Arizona Water under the PCG settlement, address Staff's proposed rate design for the Company's Eastern Group, discuss consolidation of the Superior and Apache Junction systems, provide further consideration of the risks impacting the Company's cost of capital, discuss a revised depreciation methodology, address issues related to the Company's NP-260 Non-potable Water Tariff, and address recovery of the capital and operations and maintenance costs of required arsenic treatment facilities.

Q. HAVE YOU PREPARED ANY EXHIBITS AS PART OF YOUR PRESENTATION IN THIS PROCEEDING?

A. Yes, I have prepared the following exhibits that are attached to this testimony:

Exhibit RJK-R1 Staff's Response to AWC's Data Request No. 4.8

Exhibit RJK-R2 Capacity Multiples by Meter Size

Exhibit RJK-R3 Percent Of Use In Tier 3

II.

III. RATE DESIGN

Q HAVE YOU REVIEWED THE STAFF'S RATE DESIGN AND EVALUATED ITS THEORETICAL MERITS?

A. Yes, I have reviewed both the stated theoretical basis and the underlying support for Staff's experimental rate design as set forth in Mr. Thornton's direct testimony. I have also reviewed and evaluated the Staff's actual recommended rates as set forth in Mr. Ludders' testimony and workpapers for each Eastern Group system. My overall conclusion regarding Staff's rate design recommendations is that it is inadequately developed and lacks both depth and breadth of quantitative support. Instead, Staff relies on suppositions, assumptions, unsupported assertions and fails to acknowledge issues discussed in the very publications it relies on in making its recommendations.

Moreover, the design deviates from the Company's existing and proposed cost of service based rates without any supporting cost of service study. Mr. Thornton's cryptic half page calculations of Apache Junction's Average Incremental Cost (AIC) is not a cost of service study. Staff's deviation from cost of service rates is more than a theoretical concern; it creates inequitable subsidies between meter sizes in each Eastern Group system. It is folly to apply experimental and untested rate design concepts to 30,000 customers over a very large area based solely on Staff's incomplete theoretical analysis.

Q. IS STAFF'S THEORETICAL ANALYSIS CONSISTENT WITH COMMISSION POLICY?

A. No. Staff fails to even acknowledge the Proposed Tiered Rate Design Policy posted on the Commission's web site, which states in part:

> Criteria for evaluating the appropriateness and/or type of tiered rate structure on a case-by-case basis shall include, but not be limited to, the following:
>
> 1. Number of service connections on the system.
> 2. Number of high usage customers on the system.
> 3. Gallons of average water usage per connection per month.
> 4. Gallons of median water usage per connection per month.
> 5. Source of supply.

Staff makes no effort to even address these factors and, as a result, the theoretical basis of the proposed rate design is poorly explained and not supported. The proposed rates are discriminatory and fail to meet cost of service standards that specifically address the unique aspects of each system. This is rather ironic given Staff's opposition to consolidation when it is proposed by the Company to moderate rate impacts on small systems because they oppose subsidies and state that rates must be cost based. Nevertheless Staff seems perfectly willing to produce and accept subsidies within systems that require the larger meter sizes to subsidize the smaller customers.

Q. PLEASE DESCRIBE SOME OF YOUR SPECIFIC CRITICISMS AND CONCERNS WITH THE THEORETICAL SUPPORT FOR THE EXPERIMENTAL RATE DESIGN CONCEPTS ADVANCED BY STAFF.

A. Staff proposes an experimental, marginal cost rate design approach for approximately 30,000 customers in all eight Eastern Group systems that has never been used in Arizona. This novel rate design approach is not widely used by the majority of United States water utilities, especially investor-owned utilities. Many of the published articles dealing with actual use involve government-owned water utilities that normally base the current year's rates on future budgeted capacity additions.

The first citation in Mr. Thornton's testimony is to an article by Mann "Marginal-Cost Pricing: Its Role in Conservation." Staff's quote includes the following sentence.

> A few water utilities have adopted seasonal or inverted-block pricing based on estimations of marginal-cost differentials by season or demand function. The scaling requirement, however, along with other factors, has limited the appeal of this rate setting approach.[1]

However, Staff does not discuss the scaling requirement or address the other factors in the quotation that limit the appeal of this approach.

Another concern raised in the article is:

> The critical step in the AIC approach is the selection of the output denominator in calculating the AIC. The cost numerator can be divided by a measure of designed capacity. The use of designed capacity may, however, underestimate AIC because there is no recognition of reserve or unused capacity. The procedure also does not recognize the magnitude of lost or unaccounted-for water.[2]

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[1] Direct Testimony of John S. Thornton ("Thornton Direct") at 3, ls. 20-24.

[2] Dr. Patrick Mann, "Marginal-Cost Pricing: Its Role in Conservation" Published in the *Journal of the American Water Works Association* and available at http://www.cepis.ops-oms.org/muwww/fulltext/repind48/marginal/marginal.html

Yet, again, Staff does not provide any explanation of how it selected its output denominator, how they dealt with reserve or unused capacity or unaccounted for water in each Eastern Group system. More importantly Staff computes one average incremental cost or AIC for the Apache Junction system and then blindly applies it to all of the Eastern Group systems despite the significant differences between Apache Junction and the remaining small and geographically diverse systems. Reserve capacity and unaccounted-for water are not uniform throughout the eight systems, nor is investment per customer, customer growth or water demand per customer. The systems are more different than they are similar.

Q. DO YOU HAVE CONCERNS ABOUT THE OTHER PUBLICATIONS STAFF APPEARS TO BE RELYING ON TO SUPPORT ITS EXPERIMENT IN RATE DESIGN?

A. Yes. Staff identifies a case study applying the marginal cost principal to setting rates for water utility service. Presumably, this indicates that Staff has read, agrees with and has generally followed the article, which makes the following statements.

- The study consisted of six tasks:

    1. develop an understanding of MMWD's (the Marin Municipal Water District) water supply-demand situation, operations and customer characteristics;
    2. review the current rate structure and identify related problems;
    3. prepare a list of rate setting objectives;
    4. review and evaluate potential alternative rate structures;
    5. formulate a rate structure that best achieves the stated rate-setting objectives; and
    6. recommend a new rate structure to the board of directors.

- Marginal capital costs were developed using the long-term capital program to estimate the incremental cost of developing additional water supplies.
- The rates proposed...were intended to eliminate existing subsidies among different customer classes and between large and small users.
- Fluctuations in revenue needs would be accommodated through the build-up and drawdown of reserves.
- With a three tier rate structure, only 3 percent of water use would be priced at the highest tier in FY1993-94. Similarly, about 13 percent of the water use would be priced at the second tier. The remaining 84 percent would be priced at the first tier rate.[3]

Staff certainly has not provided any testimony to indicate that it followed any of the procedures in this article or explained why any variations might be justified. Staff also deviated from the recommended rate approach by recommending only one uniform set of break points for all meter sizes in all eight systems where the commodity cost would increase. The MMWD design, on the other hand, recognized that there should be different break points for different size users and established three breakpoints for one system based on customer characteristics to avoid subsidies and discrimination.

Q. WHAT OTHER STATEMENTS IN STAFF'S THEORETICAL RATE DESIGN DISCUSSION MAY LEAD THE READER TO INCORRECT CONCLUSIONS?

A. First, Staff makes the following statement (Thornton Direct at 6):

> Economists would say that water is 'price inelastic.' Therefore, Staff did not make any changes to test-year bill counts in conjunction with the three tiers.

The fact that water is generally regarded as price inelastic does not mean that rate design can disregard the effect of price elasticity. Price inelastic only means that the

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[3] Robert Reed and Ronald Johnson, "Developing Rates With Citizen Involvement" *Journal of the American Water Works Association*, vol. 86, no. 10 (October 1994).

percentage change in quantity is less than the related percentage change in price.

The following description of price elasticity from the NRRI manual contradicts Staff's conclusion:

> In economics, demand is viewed as the inverse relationship between price and quantity consumed. The price elasticity of demand measures the percentage change in quantity demanded in response to a percentage change in price. That is, price elasticity measures the sensitivity of quantity consumed to price changes. Estimating price elasticity is an important component of demand forecasting and revenue projection. If a rate change is anticipated, its effect on demand and revenues must also be anticipated by utilities and their regulators.[4]

The discussion goes on to give some estimates of price elasticity for water demand.

> The literature as a whole suggests that a likely range of elasticity for residential water demand is between -.20 and -.40, which is relatively price inelastic.[5]

According to Staff's response to Arizona Water's Data Request No. 4.8, Staff relied on the entire NRRI handbook "Cost Allocation And Rate Design For Water Utilities" to design its Eastern Group rates. *See* Staff Response to 4.8 attached hereto at Exhibit RJK R-1. However, this does not actually appear to be the case.

Given a single price increase of 20% the percentage change in quantity of water demanded at elasticities of -.20 and -.40 would be -4% and -8%, respectively. Staff's tiered rate design incorporates two 20% price increases and ignores the effects of price elasticity. Price really does matter as made clear by the customers from San Manuel appearing at the public comment session on June 23, 2003 who stated that

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[4] **"Cost Allocation and Rate Design for Water Utilities". Published by National Regulatory Research Institute, December 1990, page 31.**

[5] *Id.*

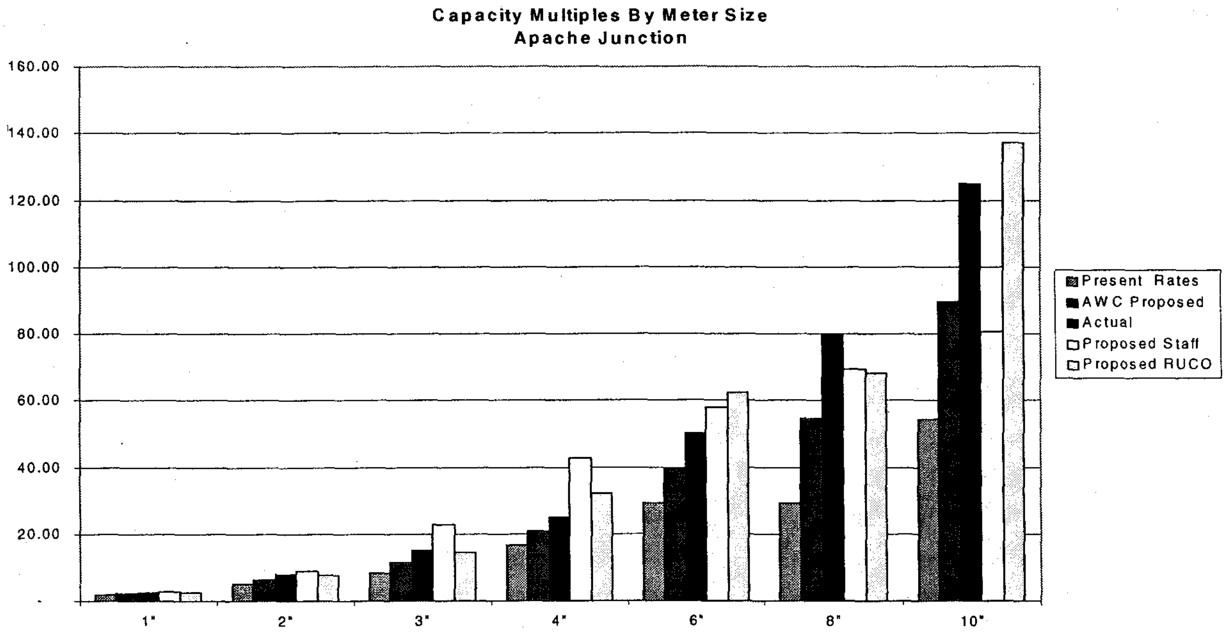
price increases would affect their consumption.

Second, to demonstrate that the Commission has previously approved inverted block rates for water utilities, Mr. Thornton cites four recent Commission Decisions. Thornton's Direct at 7. Each of those utilities has approximately 500 customers. Although these systems have something in common with the Winkleman system, the fact that they have tiered rates, some of which appear to have been requested by the utility, is not an argument for adopting experimental tiered rates for the 30,000 Eastern Group customers in eight different systems.

Q. HAVE BOTH STAFF AND RUCO DEVIATED FROM THE EXISTING COST OF SERVICE BASED RATES?

A. Yes. The existing rates, like those in the recent Northern Group Rate Case, became effective in January 1993 and were based on a cost of service study submitted by the Company. Docket No. U-1445-91-227.The actual authorized rates deviated somewhat from the pure cost based rates to moderate the impact on customers. There were two main adjustments. The recommended elimination of 1,000 gallons of free water in the minimum charge was postponed. The other change to moderate the impact on larger meter sizes was to delay full implementation of the actual meter multiples. A meter multiple scales the minimum rate for the 5/8" meter by the capacity multiple of each larger sized meter. The Company's proposed rate design, which followed the same principles as recommended and approved in the recently concluded Northern Group Phase I rate case, addressed the two moderating adjustments reflected in the existing, cost based rates. First, the 1,000 gallons of free water in the minimum charge was eliminated. Second, following the principle of gradualism in rate design, each system's existing meter multiples were moved half way toward the actual meter multiples. The existing cost based meter multiples, the Company's recommended multiple, the actual capacity multiple, Staff's proposed multiple and RUCO's proposed multiple for each meter size in each system are illustrated on Exhibit RJK R-2.The first chart of this exhibit, for the Apache Junction system, is shown below.

The first three bars for each meter size (existing cost based meter multiples, Arizona Water's recommended multiple, the actual capacity multiple) demonstrate the logical, consistent and gradual movement of the existing meter multiples in the



Company's proposed rate design toward the actual capacity multiple in the third bar. The illogical, haphazard and erratic changes proposed by Staff and RUCO's proposed rate designs is confirmed by looking at their meter multiples, shown as the fourth and fifth bar respectively in the above chart and all the Charts of Exhibit RJK R-2. Sometimes they exceed the actual capacity multiplier (the third bar) and at other times they are below it.

Q. **WHAT DOES YOUR EVALUATION OF THE STAFF'S EXPERIMENTAL RATE DESIGN SHOW?**

A. There is a one overriding, fundamental and ultimately fatal flaw in Staff's proposed rates: discrimination among meter sizes to favor the smaller size meters with lower use. In each of the eight Eastern Group systems, Staff is proposing a disproportionate increase in the larger size meters. This discrimination in Staff's proposed rate design comes about in two ways. First, by increasing the meter multiples beyond the actual capacity multiple (the third of the five bars shown on Exhibit RJK R-2 for each system and meter size. As the exhibit shows, this discrimination also is present in RUCO's rate design proposal. Second, Staff goes on to discriminate against the larger size meters by recommending only a single set of break points (the consumption levels above which a higher price commodity tier becomes effective) for all meter sizes and all eight systems. The percent of commodity use that is priced at the highest Tier 3 level for each Apache Junction meter size is presented on Exhibit RJK R-3 to illustrate the problem. This exhibit shows that the 5/8-inch meter category consumption does not go beyond the second 50,000 gallon break point. However, each larger size meter has an increasing percentage of consumption above the third 100,000 gallon break point that is subject to the highest Tier 3 commodity rates. The upward sloping trend line is further graphical evidence of the benefit given to the 5/8-inch meter customers to the detriment of customers' with the larger size meters.

The linear trend of percentage increases across all meter sizes confirms the clearly discriminatory effect of Staff's proposed experimental rate design on the Apache Junction customers. Since the same tiered rate design, with a single, uniform set of break points is applied to each Eastern Group system, the resulting rates for the other systems will show a similar trend to the Apache Junction trend shown on Exhibit RJK R-3.

In short, Staff's proposed experimental rate design is a bad experiment that should not be imposed on 30,000 Eastern Group customers. It should be sent back to the drawing board for a complete overhaul and then tried out a smaller systems until its results are predictable. It is shear folly to recommend such a radical and untested rate design concept for 30,000 customers. In the future each system's unique characteristics must be considered and utilized to design fair and non-discriminatory rates. There is no easy solution to developing reasonable and non-discriminatory rates of the type Staff is proposing. It requires much more work, analysis, evaluation and explanation than Staff has devoted to the task in this proceeding. Staff's rate design and RUCO's should be rejected.

IV. APACHE JUNCTION AND SUPERIOR SYSTEM CONSOLIDATION

Q. HAS THE COMPANY REVIEWED THE STAFF'S RECOMMENDATION CONCERNING CONSOLIDATION OF THE APACHE JUNCTION AND SUPERIOR SYSTEMS?

A. Yes, Mr. Whitehead and I have reviewed and will comment on Staff's recommendation related to the consolidation of the Apache Junction and Superior systems. Mr. Hammon bases his opposition to rate consolidation at this time on two reasons. The first reason is that Mr. Hammon believes that a detailed cost of service study would need to be presented to address alleged inequalities. The second reason for Mr. Hammon's opposition is that the systems are not physically interconnected at this time. Mr. Hammon believes that a detailed cost of service study would need to be presented to address alleged inequalities. Hammon Direct at 3.

Q. DOES THE COMPANY AGREE?

A. No. The Company disagrees with Mr. Hammon that a detailed cost of service study is needed to address alleged inequalities. It is interesting that Mr. Hammon doesn't believe that a detailed cost of service study is required for Staff's proposed experimental rate design but believes it is required for consolidation. The Company's initial step toward consolidation would merely unify the monthly minimum rates that would be charged. Apache Junction's and Superior's billing districts would be maintained and customers would be billed at the rates authorized in this proceeding, which would include a unique commodity charge for each system. Direct Testimony of Ralph J. Kennedy at 11. Then, in a subsequent Eastern Group rate proceeding, the Company would propose a common commodity charge for all Apache Junction and Superior customers, the second step of the proposed rate consolidation.

Mr. Hammon expressed a concern over consolidation since there was no physical interconnection. Today's Staff may think this is a requirement for consolidation but it runs counter to over thirty-five years of Commission decisions on the Company's applications that approved rate consolidation without requiring a physical interconnection. Physical interconnection was never a necessary condition for previous Company rate consolidations and it shouldn't be now. It is wrong to elevate interconnection above so many other important considerations.

Physical interconnection, however, will be a fact before the next Eastern Group rate case is filed and rate consolidation should be positively addressed now to reduce the overall impact on customers in the next Eastern Group general rate case. Two gradual steps are preferable to one large disruptive step in the next rate case after interconnection. has been completed. As Mr. Whitehead testified there is a timetable for interconnecting these systems. On December 27, 2001, the Company filed an application with the Commission requesting approval of an extension of its existing CC&N to include additional properties in Pinal County, the area that would physically interconnect the two systems. *See* Docket No. W-01445A-01-1012. A Staff Report in the referenced docket was issued in May 2003 and a hearing was conducted on July 24, 2003. Staff recommended approval of the application for the extension of Arizona Water's CC&N subject to three compliance conditions: 1) Company is required to charge its existing Apache Junction rates and charges in the proposed extension area; 2) Company is required to file a Curtailment Tariff and report within 30 days of the effective date of any decision in this matter (the CC&N matter); and 3) Company is required to file a developer's Certificate of Assured Water Supply related to the proposed extension area within 365 days of the effective date of the decision in this matter (CC&N matter).

If the application is approved and the CC&N extended, the Apache Junction and Superior systems will then be physically interconnected. At that point, all indications are that Apache Junction and Superior will be able to share water supplies providing additional reliability and CAP water to the Superior customer base and providing a larger base of customers to the Apache Junction system to support required facility additions such as arsenic treatment facilities and new wells. As such, consolidation would be beneficial to both Superior and Apache Junction customers and should be approved at this time.

Q. **MR. WHITEHEAD HAS TESTIFIED THAT APACHE JUNCTION AND SUPERIOR WILL BE INTERCONNECTED WITHIN TWO YEARS. WHAT HAPPEN IF THESE SYSTEMS ARE NOT COMBINED FOR RATE PURPOSES NOW IN THE TWO STEP PROCEDURE RECOMMENDED BY THE COMPANY?**

A. Based on the Company's original request Apache Junction revenues would have to increase 16.7%, on a stand-alone basis, and Superior's would have to increase 71.4%. These percentages are based on the current revenue requirements for each system. They do not include the further impact of arsenic treatment facilities and their annual operating cost. The Superior system's arsenic treatment facilities will have a construction cost of $1,682,813 which is 63% of Superior's original cost rate base of

$2,673,576 as proposed by the Company (Schedule B-1, page 2, line 8). the Superior system will also incur additional annual arsenic treatment Operation and Maintenance expenses of $182,374 based on evidence submitted by the Company in the Northern Group Phase II ACRM proceeding (Exhibit RJK2-4). Since these systems will be interconnected before the next general rate application, beginning the eventual rate consolidation now, in the two step procedure the Company recommends, offers at least three distinct advantages. First, by consolidating the minimums now and the commodity rates in the next proceeding, the required revenue increase for Superior can be reduced from 71.4% to 8.9%. This is achieved with less than a 6% additional increase in Apache Junction's revenue requirement from 16.7% to 22.2%. Second, a larger combined system will moderate the arsenic impacts on the already overburdened Superior customers. Finally, the Company's two-step-proposal would move the rates of each system closer together now rather than driving the existing stand alone rates even further apart as Staff and RUCO recommend. The Company's proposed gradual approach will simplify and minimize both the consolidation impact in the next rate proceeding and the impact of arsenic treatment facilities on the Superior customers.

V. <u>COST OF CAPITAL RISKS</u>

Q. DO YOU AGREE WITH STAFF REGARDING ADDITIONAL RISKS ASSOCIATED WITH PLACEMENT OF BONDS IN THE CAPITAL MARKETS?

A. No. I do not. *See* Direct Testimony of Joel M. Reiker ("Reiker Direct") at page 55, ls. 16-24. Like much of Mr. Reiker's testimony, the Company disagrees with Staff's general approach as well as its conclusions. Dr. Zepp will elaborate in far more detail in his rebuttal testimony, as supplemented by my testimony.

Q. HAS STAFF PROPERLY ACCOUNTED FOR THE COMPANY'S EXPERIENCE AND DIFFICULTY IN PLACING ITS SERIES K BOND ISSUE?

A. No, Mr. Reiker continues to ignore the Company's experience before it was finally able to issue its Series K bonds. In dismissing Dr. Zepp's claim that Arizona Water faces additional risks in placing future bond issues, Mr. Reiker avoids making the necessary cost of capital adjustments to address this additional risk. *See* Reiker Direct at pages 55-56, ls. 16-24, 1-5.

Q. WHAT EMPIRICAL EVIDENCE CAN YOU CITE REGARDING THE MARKET FOR THE COMPANY'S BONDS?

A. Unlike prior bond solicitations to insurance companies, not one of the potential buyers even responded to our September 2000 request for bids. By comparison, in 1990, the Company was able to choose from ten alternative bids within two weeks of issuing its request and received a binding purchase commitment in less than five weeks.

Q. HOW DO YOU EXPLAIN THE LACK OF RESPONSES TO THE COMPANY'S SEPTEMBER 2000 REQUEST FOR BIDS?

A. I specifically contacted a number of potential purchasers to determine why they had not responded to our solicitation. The directors of private placement with whom I spoke told me that $20 million to $25 million was the minimum issue they would consider, preferring issues in the $50 to $100 million range. They also expressed a preference to acquire larger, more liquid issues for their portfolio rather than several smaller, lesser-known issues as their costs of due diligence, accounting and administration do not vary significantly for issues between $10 and $100 million.

Q. HOW IS THE CURRENT MARKET FOR THE COMPANY'S BONDS DIFFERENT FROM THE 1990 MARKET?

A. The market for the Company's bonds has undergone fundamental changes and now consists of fewer but larger companies with more sizeable investment portfolios. A number of the companies we formerly did business with have merged or been acquired, increasing the size of the remaining entities. Many of the larger, leaner, more sophisticated entities have an appetite for much larger bond issues. Their financial staffs have been reduced and their portfolios combined. For example, First Colony Life Insurance Company purchased our entire $6 million Series J Bond issue in 1990, although we also had less competitive bids for various portions of that issue. General Electric Company has since acquired First Colony. Occidental Insurance Company and Transamerica Insurance Company, former bidders and bondholders, are now Aegon USA Investment Management Inc. Indianapolis Life Insurance Company, a former bondholder, is now AmerUS Capital Management. The Franklin Life Insurance Company, another former bondholder and bidder, is now American General Investment Management.

Q. WHAT STEPS DID THE COMPANY TAKE WHEN IT REALIZED THAT IT WAS FACING A DIFFERENT MARKET FOR ITS BONDS?

A. After the failure of the first September 2000 bond solicitation, two potential purchasers with large investment portfolios that were not on the initial request for bids list were identified in November and December of 2000. These large potential purchasers were willing to negotiate buying the Company's Series K issue but stated up front that they would require a "liquidity premium." Without any other interest in our bonds, the Company began negotiations with both entities. In subsequent negotiations with Matthew Armas of General Electric Financial Assurance and Mr. Ben Vance of Provident Investment Management, the potential purchasers added a "liquidity premium."

Q. DO YOU KNOW THE SPECIFIC REASONS WHY THESE LARGE, SOPHISTICATED INVESTORS REQUIRED A "LIQUIDITY PREMIUM"?

A. Yes. I specifically inquired as to why they demanded a "liquidity premium." They expressed the following concerns about the Company's Series K issue:

1. The size of our proposed issue.
2. The small size of Arizona Water Company.
3. The small number and value of other outstanding issues.
4. The low number of holders of outstanding issues.

These potential purchasers concluded that because of these factors, selling or trading our Series K issue would be more difficult than other issues in their portfolios. In fact, General Electric finally concluded it wasn't interested in our bonds even with a "liquidity premium." Actual investors in the Company's common stock are likely to have the same concerns.

Q. WHAT HAPPENED WITH THE PROVIDENT NEGOTIATIONS?

A. Before accepting Provident's terms, the Company learned that Pacific Mutual had received approximately $15 to $20 million of new long-term money that it wanted to invest for thirty years. I immediately flew to California and met with Pacific Mutual's Director of Private Placements. Fortuitously, their new requirements happened to dovetail almost exactly with the Company's needs. Less than two weeks after learning of their new requirements, we were able to agree on significantly better terms for the Series K issue than Provident was demanding.

Overall, however, it took the Company 141 days to obtain a purchase commitment for its Series K bond issue as compared to only 34 days for its Series J bond issue. Although the Series K issue was 2 ½ times larger than the Series J issue, it was still too small for most of the now larger potential buyers.

Q. ARE THERE OTHER COMPANY-SPECIFIC REQUIREMENTS THAT IMPACT THE RISK FACTORS THAT SHOULD BE REFLECTED IN THE COMPANY'S COST OF CAPITAL?

A. Yes, particularly the costs of constructing and operating the required arsenic treatment facilities. By January 23, 2006, the Company must design, construct and operate arsenic treatment facilities to comply with the revised arsenic maximum contaminant level ("MCL") standard recently adopted by the United States Environmental Protection Agency ("EPA"). The arsenic treatment facilities must have a combined total treatment capacity of 60.65 million gallons per day. The Company's total arsenic treatment capital costs are estimated to be $30 million. By 2006 at the latest, annual arsenic treatment O&M expenses will have increased to $5.3 million annually. Given the limited time frame between now and the EPA's January 23, 2006 deadline and the task facing the Company to finance an additional $30 million and construct as many as fifty arsenic MCL facilities company-wide, the deadline will not be met if earnings or cash flow during this period become inadequate. Even if an ACRM that follows the Staff and Company's recommendation in the Northern Group's Phase II proceeding is adopted for both the Northern Group in that proceeding and then also for the Eastern Group in this proceeding, it will only pertain to completed, in-service arsenic treatment facilities. Although the Western Group accounts for 46% of the arsenic costs, due to the time it will take to complete a rate case there will be no ACRM to provide partial relief for the Western Group. The risk of obtaining construction financing and dealing with at least the first 12 months of annual arsenic O&M expenses for each facility will continue to stress the Company's earnings and ability to finance the required facilities.

The Company is currently awaiting a Commission decision on its request in

Phase II of the Northern Group's rate case for an Arsenic Cost Recovery Mechanism ("ACRM"). In that proceeding, the Company presented evidence that, if the ACRM as recommended by the Company was approved, 86% of the revenue requirements for Company-wide arsenic treatment capital and operating costs would still be excluded from the adjustment mechanism (the revenue requirements for the capital and O&M arsenic treatment costs for the Eastern and Western Groups in the following table). If an ACRM is approved for both the Northern and Eastern Groups 46% of the total Company revenue requirements for the capital and O&M arsenic treatment costs will still be excluded from the adjustment mechanism. There is not sufficient lead time to complete a general rate case for the Western Group and put an ACRM into effect. The following table summarizes the arsenic treatment capital costs anticipated for Arizona Water Company.

ARSENIC TREATMENT CAPITAL COSTS BY GROUP

	Dollars	Percent
Northern Group	**$ 3,950,449**	**13.4%**
Eastern Group	**12,052,993**	**40.8%**
Western Group	**13,555,971**	**45.9%**
Total Company	**$ 29,559,412**	**100.0%**

The arsenic treatment O&M revenue requirements are at least equal to the arsenic treatment capital revenue requirements.

If an ACRM comparable to the recommendation by the Company in the Northern Group Phase II is authorized for the Eastern Group as requested in this docket, the annual revenue requirement for approximately $14 million of capital costs for the Western Group will still be excluded from an adjustment procedure along with the related and approximately equal arsenic treatment O&M costs. Since the proposed Northern Group ACRM deals with completed, in-service arsenic treatment facilities and actual historic arsenic treatment O&M., the Company must still somehow finance the construction of arsenic treatment facilities and pay to operate them. Even with the recommended but limited ACRM, the Company faces unique arsenic risks that will not be experienced by the companies in the Staff's comparable entities and the cost of capital must be adjusted to reflect these unique additional risks.

Q. WHAT OVERALL WEIGHTED COST OF CAPITAL ARE YOU RECOMMENDING?

A. I am not recommending a revised overall weighted cost of capital at this time. I will make such a recommendation in my rejoinder testimony if necessary.

VI. DEPRECIATION METHODOLOGY

Q. STAFF RECOMMENDS ADOPTION OF NEW COMPONENT RATES APPLICABLE TO ALL OF ARIZONA WATER'S EIGHTEEN SYSTEMS. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. The Company is not opposed to the new component depreciation rates set forth on Exhibit E to Mr. Hammon's direct testimony. Application of the new component rates in the Eastern Group can begin upon issuance of a decision in this proceeding. However, the application of the new component rates in the Northern and Western Groups, on the other hand, should not occur until the completion of the Northern and Western Groups' next general rate case in which the associated increase or decrease in expense can be incorporated into the appropriate group's rates.

VII. NP-260 CAP TARIFF

Q. STAFF IS RECOMMENDING MODIFICATIONS TO THE EXISTING NP-260 TARIFF. DOES THE COMPANY AGREE WITH THE PROPOSED

CHANGES?

A. The NP-260 Non-Potable Central Arizona Project Water Tariff ("NP-260 tariff") was designed to pass through to the non-potable customers all of the costs involved in providing non-potable water service plus amounts for administration so as to be as income neutral as possible while avoiding passing costs onto the potable customers. The NP-260 tariff, as designed, places all of the applicable costs of service on the appropriate customers while encouraging the conservation of groundwater. The changes being proposed by Staff may seem trivial on their face, but maintaining the proper split of all applicable non-potable costs is fundamental to the Company's position on its NP-260 tariff. The Company agrees with Staff's proposal to eliminate the depreciation expense component from the NP-260 tariff. Hammon Direct at 16.

Mr. Hammon is also recommending a revision to the fixed monthly meter charge (*id.*), which was based upon the monthly minimum charge applicable to customers having comparable meter sizes. The rationale was that if the cost of service for a comparable sized meter dictated a monthly minimum of X dollars, then the same monthly minimum should be charged to the non-potable water user. The Company agrees with this concept and believes that the existing tariff language in item 2 in the **MONTHLY BILL** section already does this. Item 2 states: "A meter change based on the applicable monthly minimum charge by meter size as set forth in each systems General Service tariff schedule." The existing language is sufficient to adjust the meter charges for the NP-260 customers to the same revised amount as the General Service customers' meter charge. The monthly minimum charges that are approved as a result of a decision in this proceeding will become the "applicable monthly minimum charge..." when the Company files new General Service tariffs. Mr. Hammon is also recommending revision to the administrative charges to be representative of the Company's actual administration costs. *Id.* The Company believes that the estimated percentages in the current tariff are sufficiently representative and should be continued. Finally, in addition to the foregoing tariff revisions, Mr. Hammon is recommending revised terms and conditions of service to place a greater burden on the Company on the operation and protection of the non-potable service facilities, which have not been defined. *Id.* at 17. The decision adopted in the SLV Properties complaint concluded that the Company properly charged maintenance fees and related charges to the customer in that proceeding. Decision No. 65755 (March 20, 2003) at 8, ls. 21-23. Staff's recommendation would improperly shift this responsibility to the Company and the future costs to the potable customers and therefore should not be adopted. In summary, except for eliminating the depreciation component of the NP-260 tariff, the remainder of Mr. Hammon's proposed changes are not necessary and should be rejected.

VIII. <u>RECOVERY OF ARSENIC TREATMENT COSTS</u>

Q. STAFF'S RECOMMENDATION FOR COST RECOVERY OF CAPITAL AND OPERATING COSTS FOR ARSENIC TREATMENT WILL LIKELY BE BASED UPON THE FINAL ORDER IN DOCKET NO. W-01445A-00-0962. DOES THE COMPANY AGREE WITH THIS STATEMENT?

A. Although the Company's approach to the Northern Group procedure has been to propose an ACRM that could be used as a template for many water utilities, there will be some issues that will be unique to each of the Company's three groups. As a result of the unique issues, there may be minor differences adopted in the Eastern Group's ACRM that may not be a part of the Northern Group's. Because of this, the decision in this proceeding will have to address the Company's request for an ACRM for the Eastern Group. Overall, however, I expect they will be essentially the same. Both the

Northern Group and the Eastern Group as well as other water utilities will benefit from the time and expense the Company and Staff invested into developing an ACRM. For this reason the Company is proposing to allocate the Northern Group Phase II ACRM rate case expenses to the two groups that will be able to adopt and benefit from the ACRM, the Northern and Eastern Groups.

Q. PLEASE SUMMARIZE THE STATUS OF THE PHASE II PROCEEDINGS DEALING WITH ARSENIC TREATMENT COST RECOVERY?

A. Public hearings were held in October 2002 on the Company's request for an ACRM and the Company's proposed rate consolidation. A Recommended Opinion and Order was rendered on April 8, 2003 and considered by the Commission on April 22, 2003. At the Commission's Open Meeting of April 22, 2003, it was determined that additional evidence was needed to make a properly informed decision. Settlement discussions were conducted, additional testimony was filed on June 16, 2003, and subsequent hearings were held on June 26, 2003. Briefs will have been filed before the hearing commences in this proceeding. A new recommended order will then be issued.

Q. HOW DOES THE COMPANY ENVISION THE INCLUSION OF AN ACRM IN THIS PROCEEDING?

A. Yes. The Commission should take Administrative Notice of Phase II of the Northern Group's rate case proceeding when the hearing commences in this docket. The decision in this proceeding can adopt an ACRM comparable to the ACRM authorized for the Northern Group. The only nuance will be that the Northern Group decision will address rate consolidation for the Sedona and Rimrock systems, which will not be applicable in this proceeding. Instead, a decision on consolidating the Apache

Junction and Superior systems will be addressed as a part of this proceeding and the Eastern Group ACRM can be modified to reflect such decision.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY IN THIS MATTER?

A. Yes, except to add that the Company does not waive its right to challenge any provision or recommendation not specifically addressed in my rebuttal testimony.

EXHIBITS

STAFF'S RESPONSES TO
ARIZONA WATER COMPANY'S
FOURTH SET OF DATA REQUESTS
ACC DOCKET NO. W-01445A-02-0619

July 24, 2003

4.7 Please provide a copy of the NRRI publication *Cost Allocation and Rate design for Water Utilities* referred to on page 9 of John S. Thornton, Jr.'s testimony.

Response: Attached.

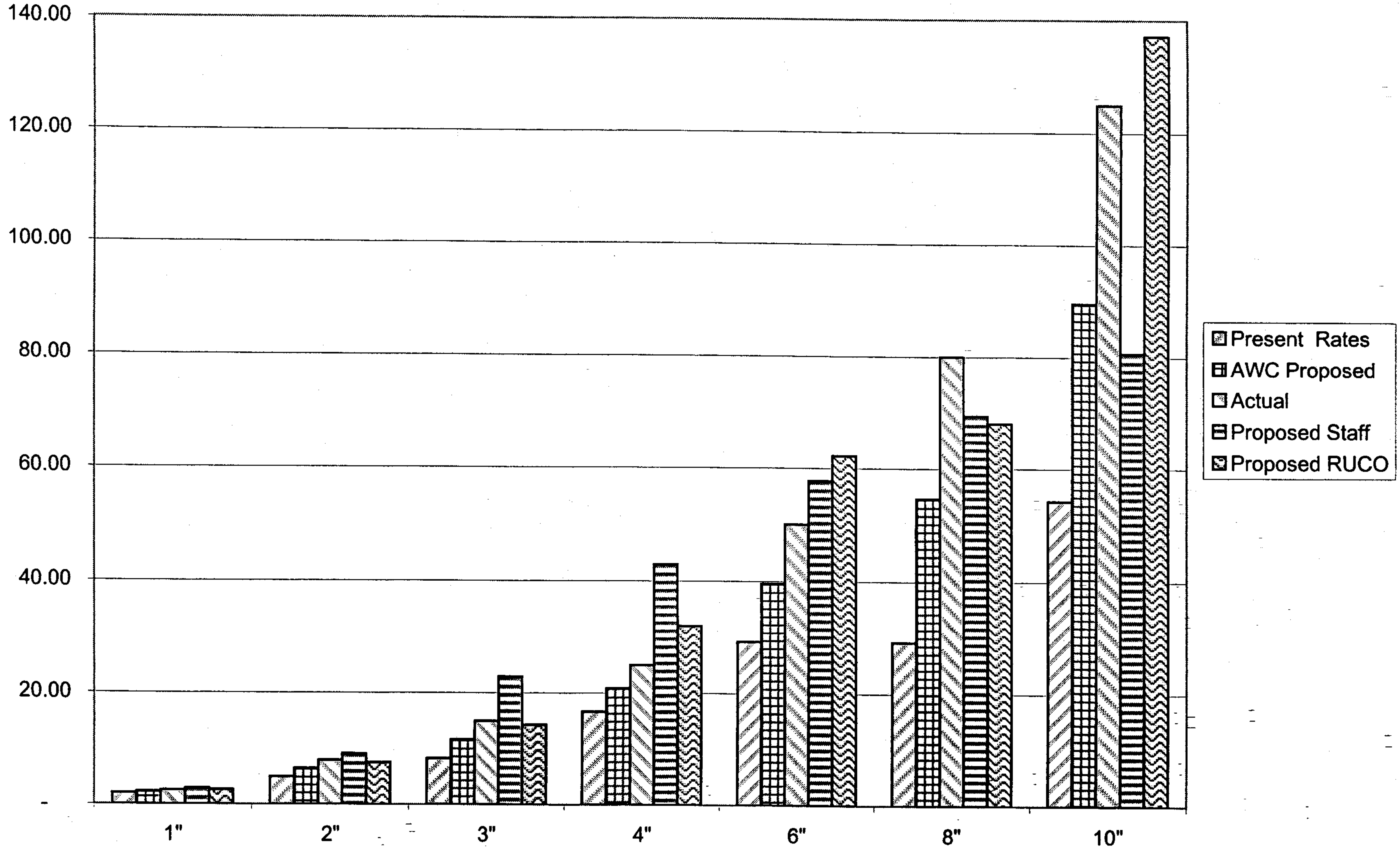
Response by: Ronald E. Ludders and Steven Olea for John S. Thornton, Jr.

4.8 Please describe and identify by page, paragraph and line numbers the specific portions of the above NRRI publication that Staff relied on in designing rates for the Eastern Group systems. If the portions of the publication identified in the first part of this question were not applied equally to the rate design of all Eastern Group systems identify the systems that received differing treatment or weight and explain Staff's rationale.

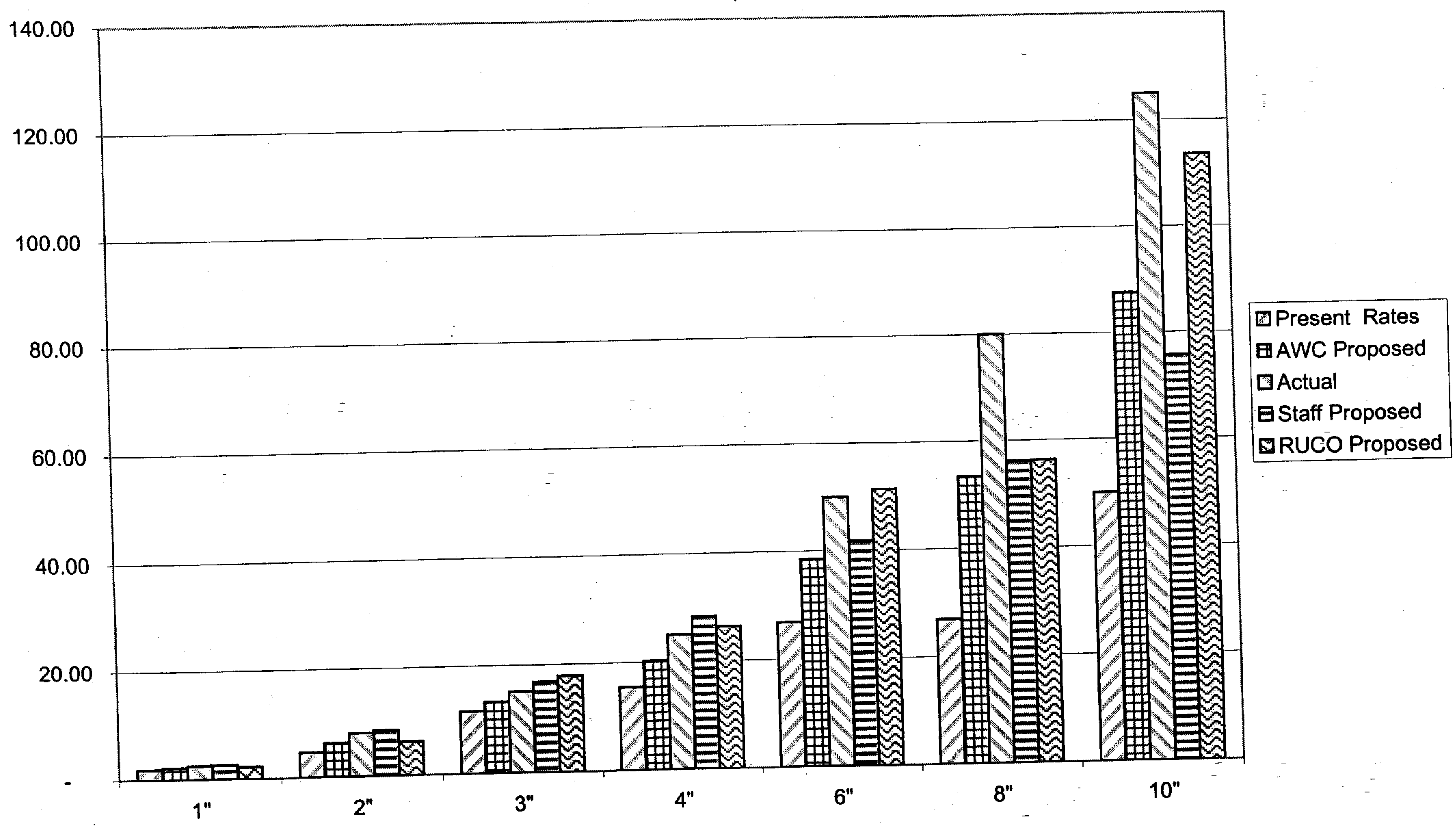
Response: Staff relied on the entire publication, especially pages 63-103 and 118-119. The publication does not contain paragraph or line numbers.

Response by: Claudio Fernandez and Steven Olea for John S. Thornton, Jr.

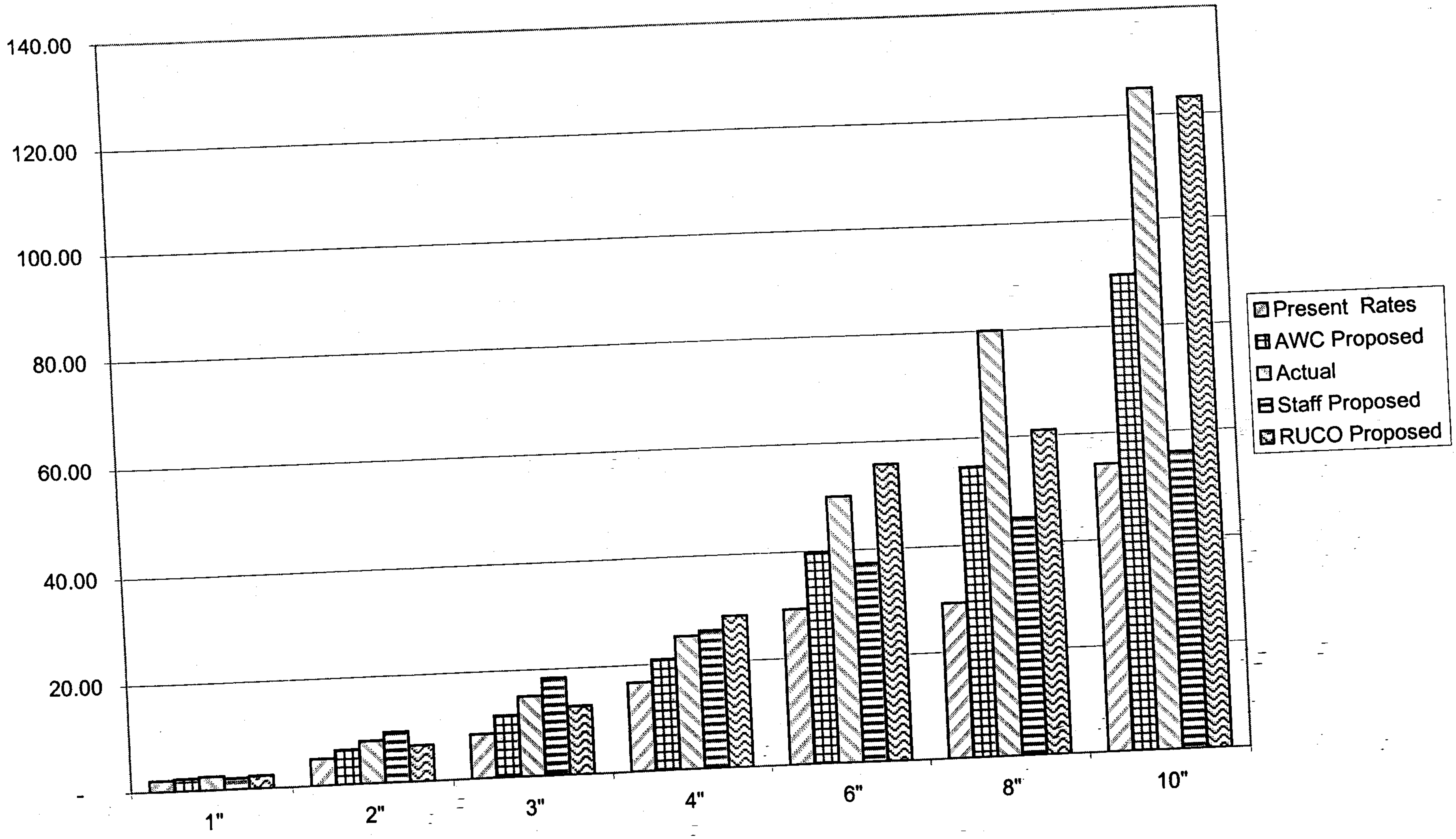
Capacity Multiples By Meter Size
Apache Junction



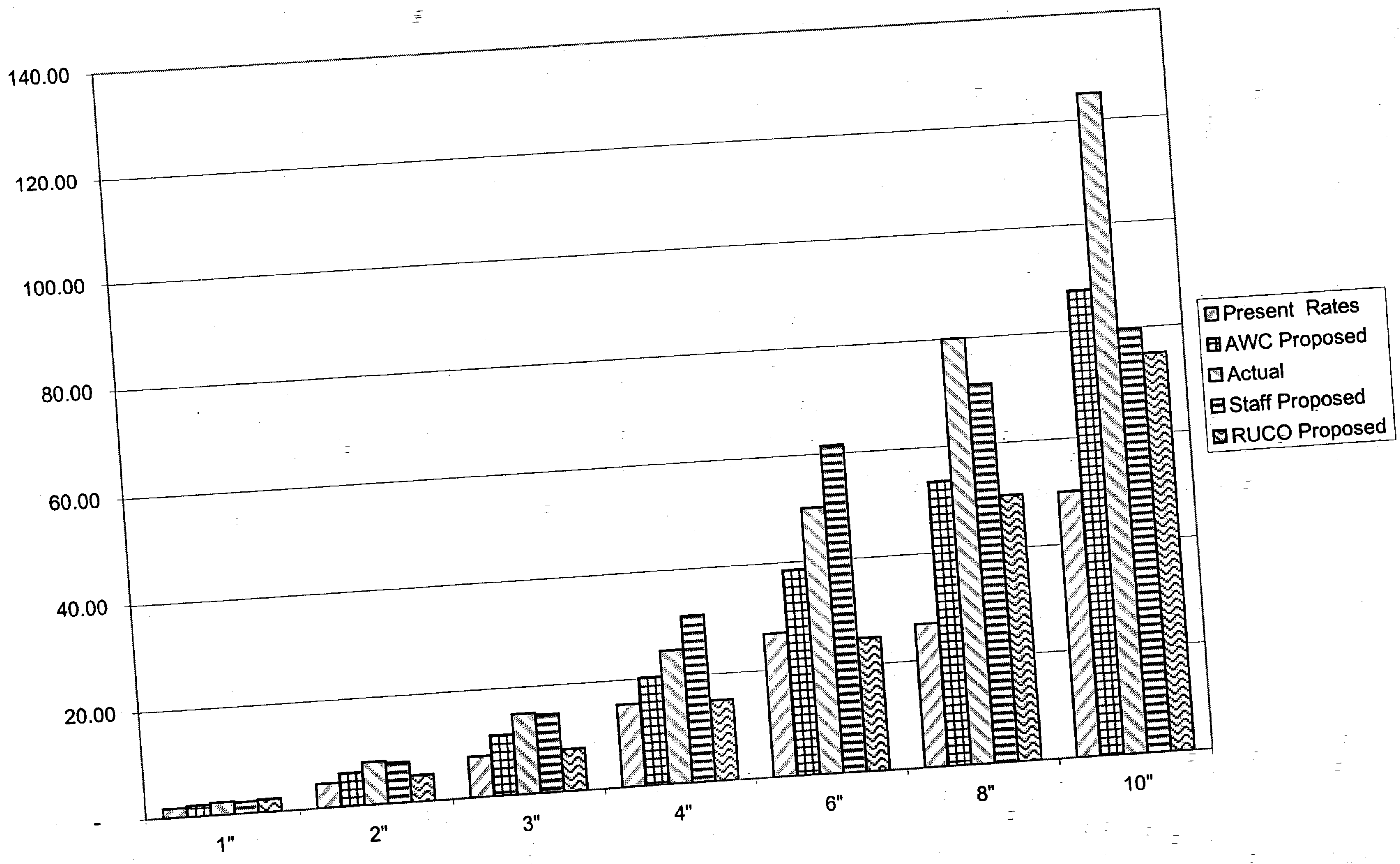
Capacity Multiples By Meter Size
Bisbee



Capacity Multiples By Meter Size
Sierra Vista



Capacity Multiples By Meter Size
Miami



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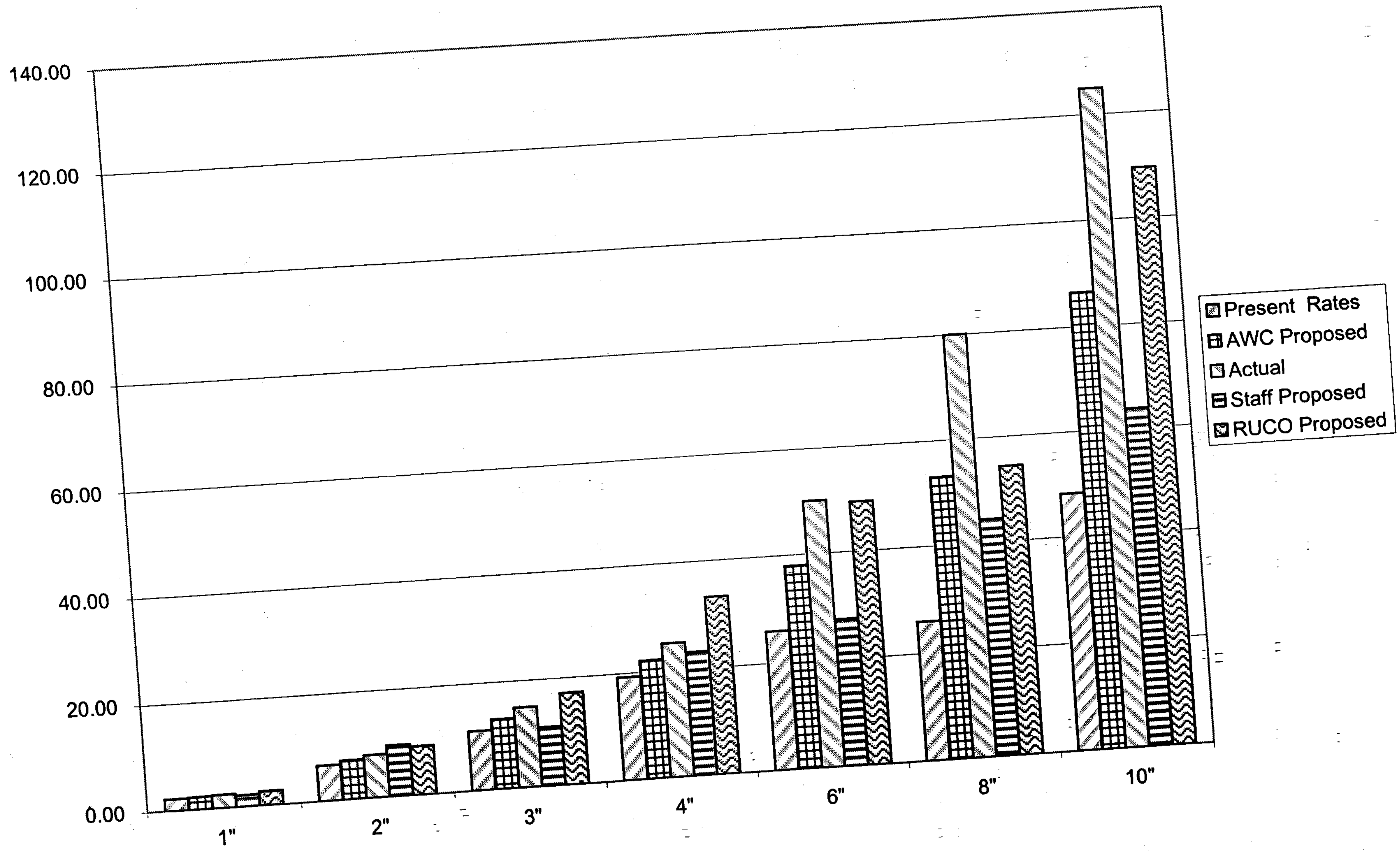
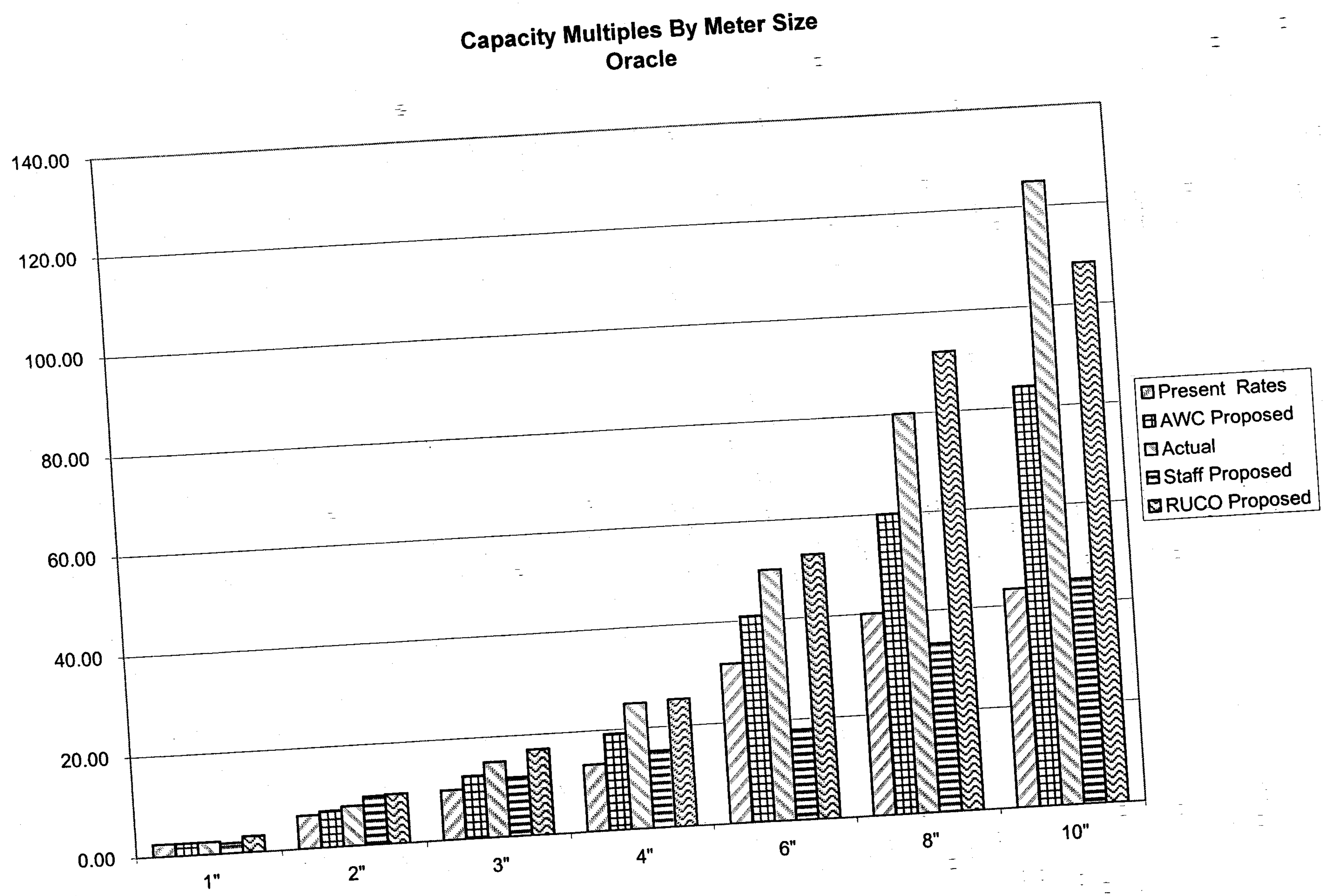
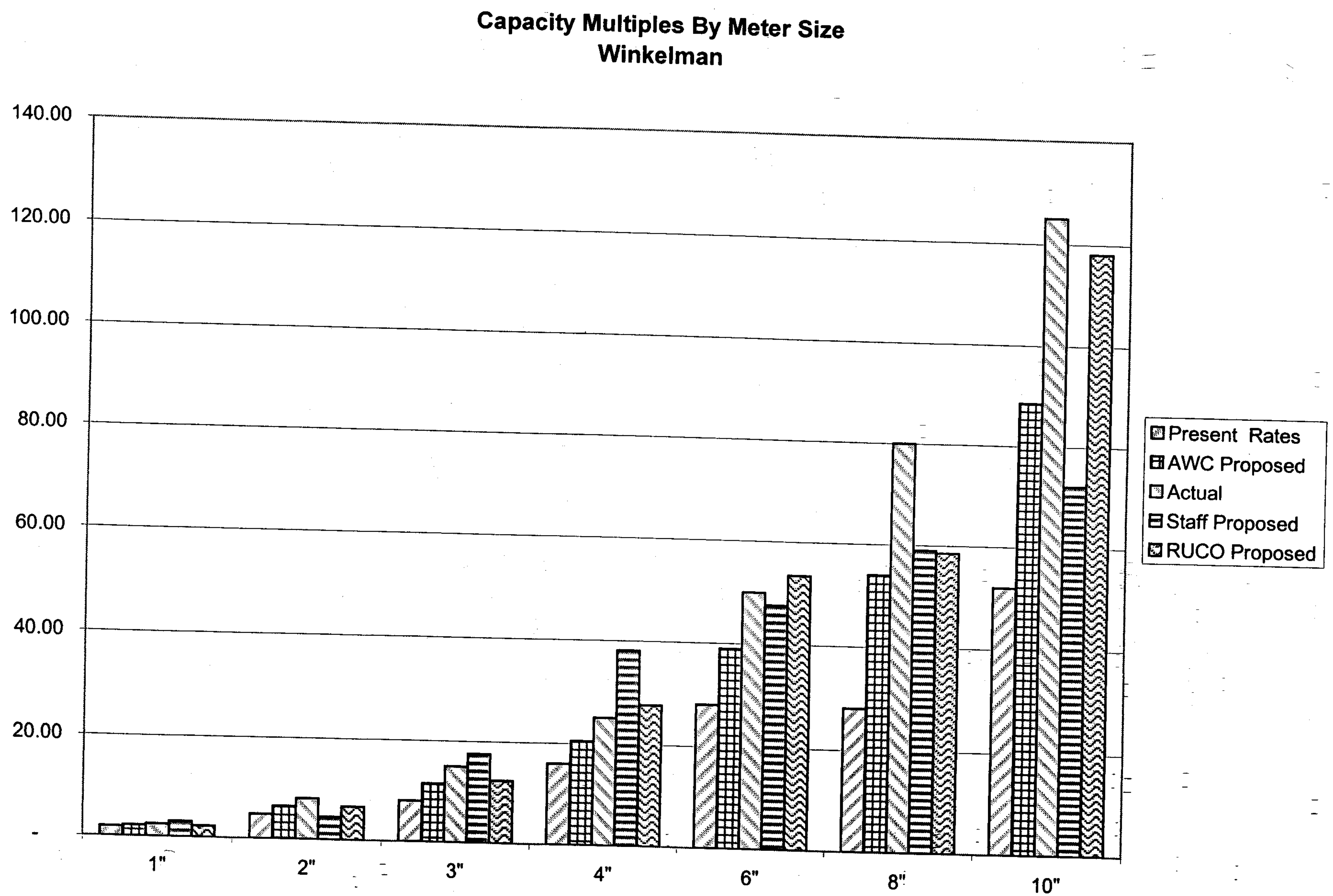
San Manuel




Capacity Multiples By Meter Size
Oracle
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
1"
2"
3"
4"
6"
8"
10"
Present Rates
AWC Proposed
Actual
Staff Proposed
RUCO Proposed


Capacity Multiples By Meter Size
Winkelman
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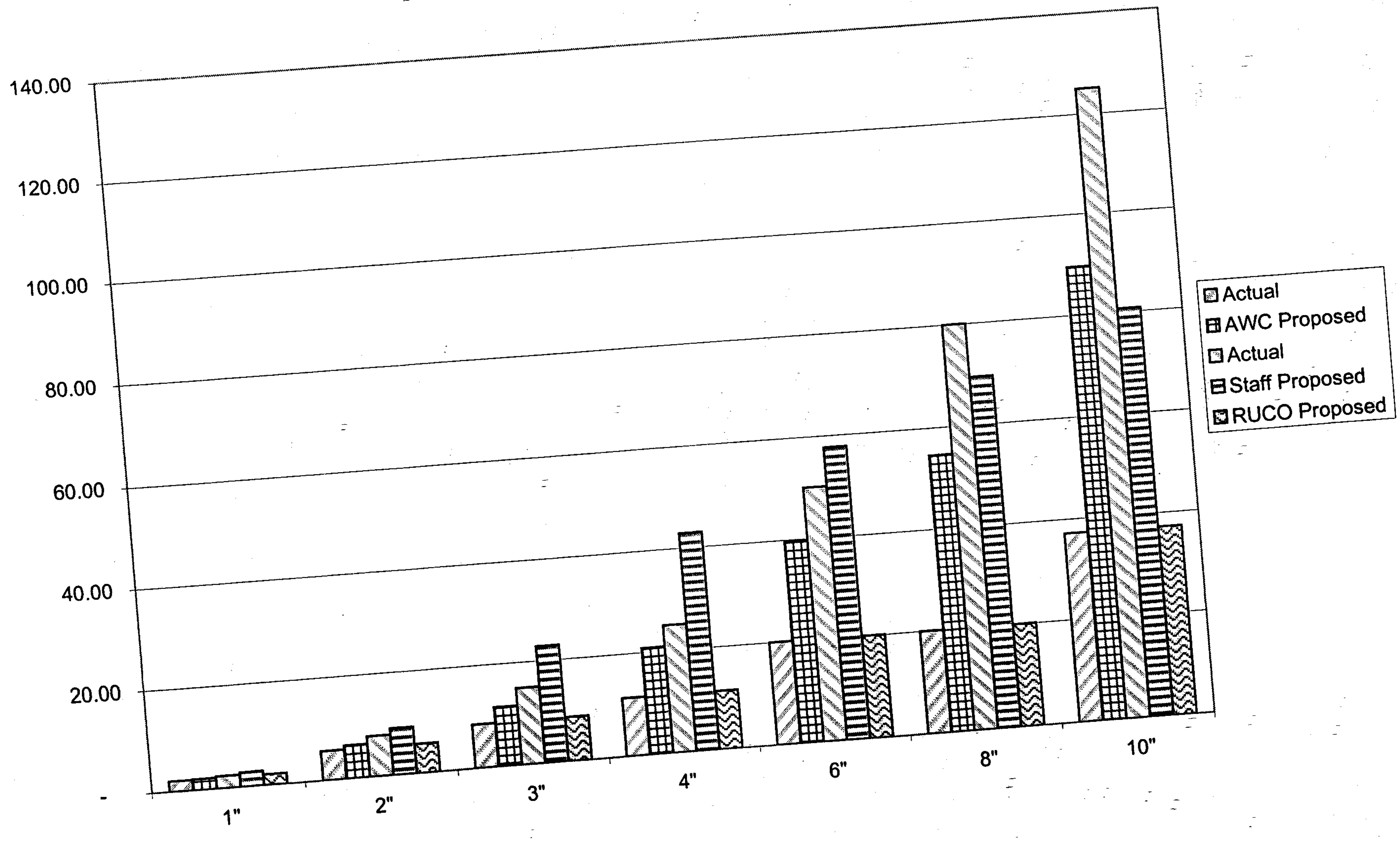
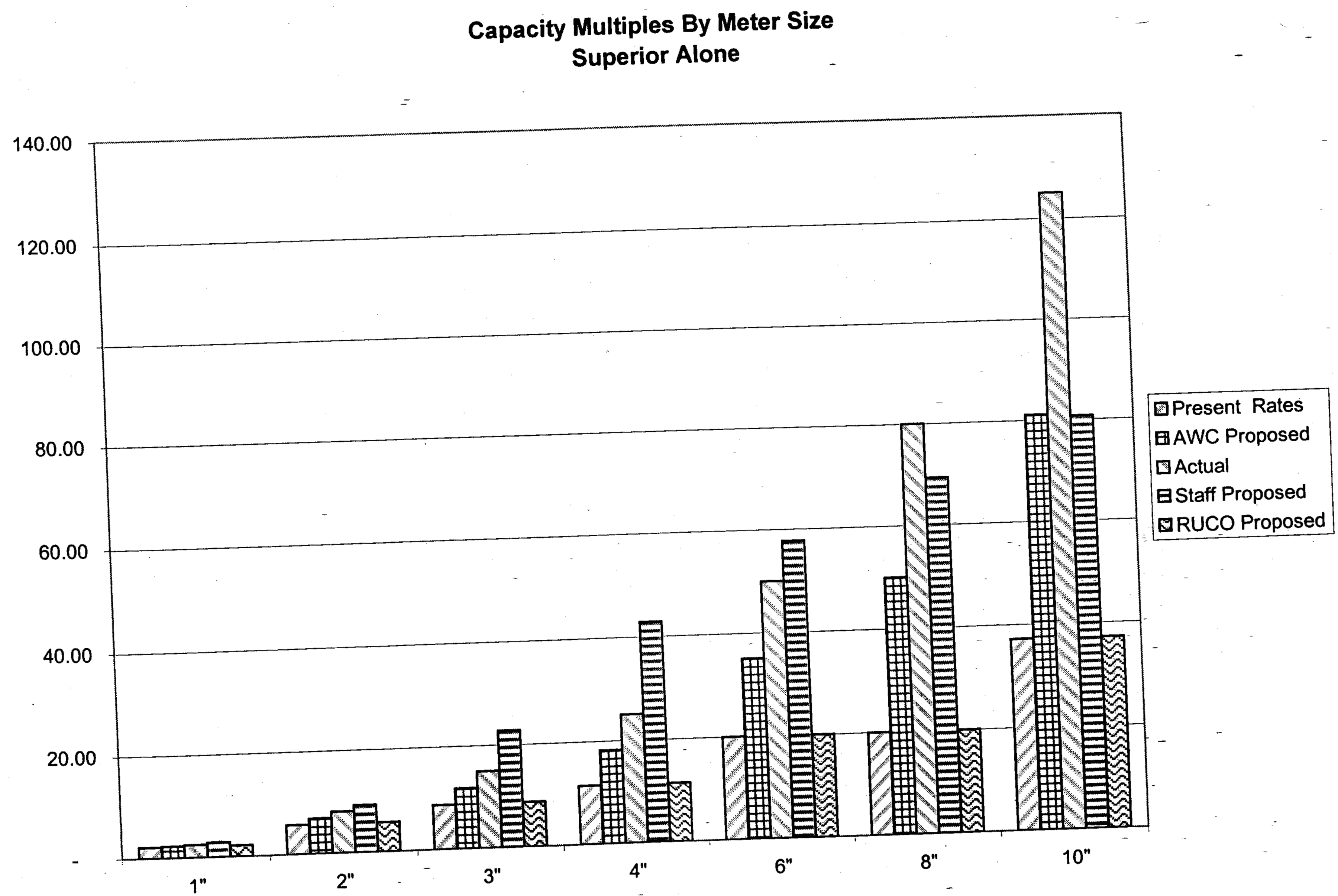
120.00
100.00
80.00
60.00
40.00
20.00
-
1"
2"
3"
4"
6"
8"
10"
Present Rates
AWC Proposed
Actual
Staff Proposed
RUCO Proposed

Capacity Multiples By Meter Size
Superior Combined W/ Apache Junction




Capacity Multiples By Meter Size
Superior Alone
140.00
120.00
100.00
80.00
60.00
40.00
20.00
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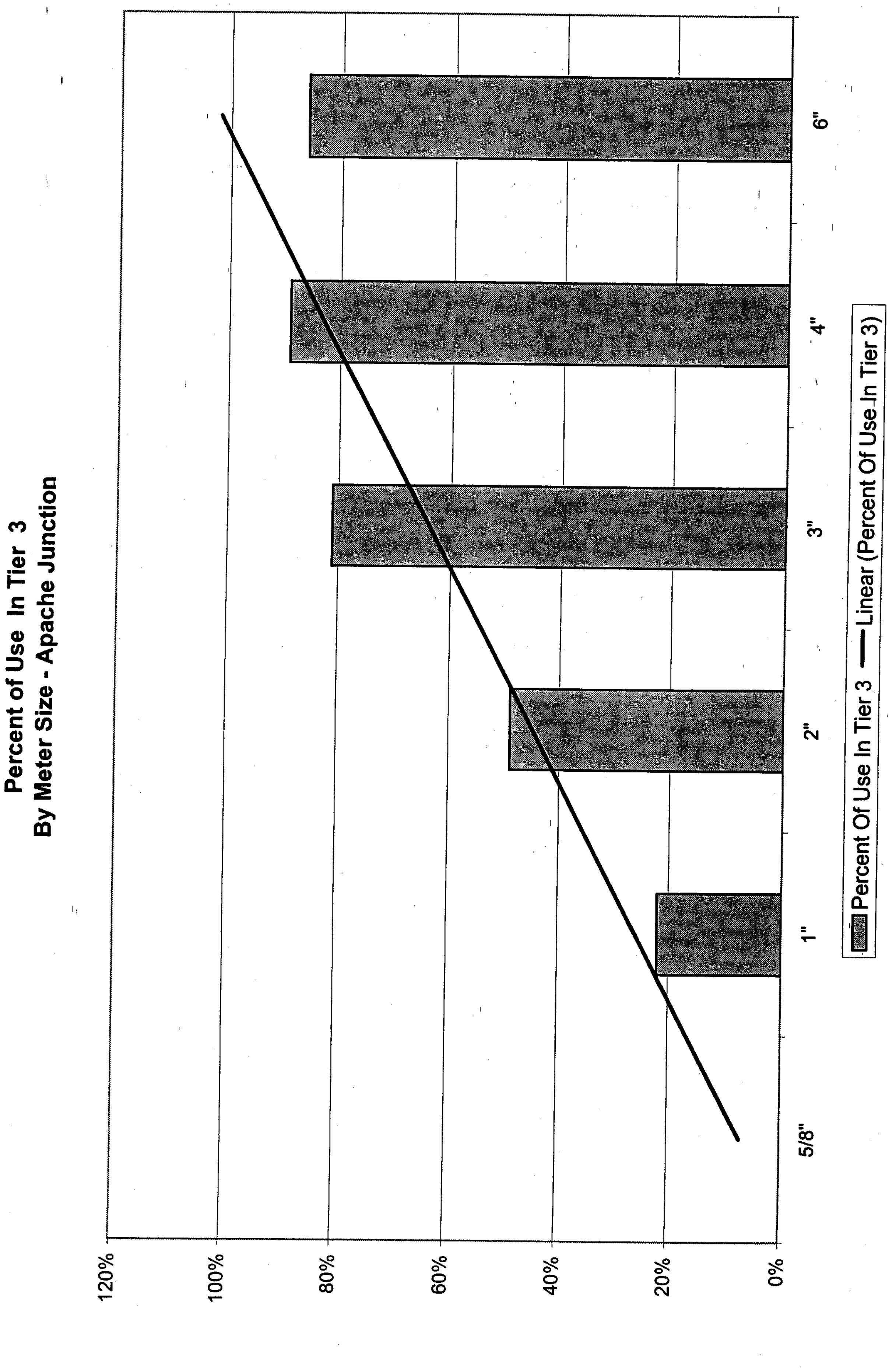
1"
2"
3"
4"
6"
8"
10"
Present Rates
AWC Proposed
Actual
Staff Proposed
RUCO Proposed


Percent of Use In Tier 3
By Meter Size - Apache Junction
120%
100%
80%
60%
40%
20%
0%
5/8"
1"
2"
3"
4"
6"
Percent Of Use In Tier 3
Linear (Percent Of Use In Tier 3)

ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

REBUTTAL TESTIMONY & EXHIBITS

OF

Walter W. Meek

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Attorneys for Arizona Water Company

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS EASTERN GROUP AND FOR CERTAIN RELATED APPROVALS.	Docket No. W-01445A-02-0619

REBUTTAL TESTIMONY OF WALTER W. MEEK

Table of Contents

I. <u>INTRODUCTION, QUALIFICATIONS AND PURPOSE OF TESTIMONY</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Walter W. Meek. My business address is 2100 North Central Avenue, Suite 210, Phoenix, Arizona 85004.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the president of the Arizona Utility Investors Association ("AUIA"), a non-profit organization formed to represent the interests of equity owners and bondholders who are invested in utility companies that are based in or do business in the State of Arizona.

Q. DOES THE AUIA MEMBERSHIP INCLUDE THE OWNERS AND OPERATORS OF ANY OF ARIZONA'S REGULATED WATER COMPANIES?

A. Yes. AUIA's members include large Class A water companies and smaller Class B and C water companies. In addition, AUIA is an associate member of the Water Utilities Association of Arizona and three of the members of the AUIA Board of Directors are from the water utility industry.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. On behalf of Arizona Water Company, the applicant.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to rebut Staff's assertion that firm-specific or so-called "unique" risk should <u>not</u> be considered in determining an equity return because investors in Arizona Water Company, or any other Arizona gas, electric, water or sewer utility providers, do not consider such firm-specific risks in making investment decisions.

. . .

. . .

Q. WOULD YOU PLEASE EXPLAIN WHY YOU ARE QUALIFIED TO PROVIDE TESTIMONY ON THIS SUBJECT MATTER?

A. I represent the largest cross-section of utility stockholders in the State of Arizona. I have been involved with the utility business in Arizona for 28 years. I have participated in dozens of Commission dockets on behalf of AUIA and testified in numerous proceedings. My testimony has covered topics including rate of return issues, stranded costs, disposition of regulatory assets, AFUDC, inclusion of CWIP in rate base and the impact of regulatory decisions on analyst and investor expectations.

Q. ARE YOU SAYING YOU ARE TESTIFYING AS AN EXPERT WITNESS?

A. I am testifying as a "real world" witness. In this docket, Staff recommends an anemic 9% return on equity based on financial theory found in some economics textbooks. Admittedly, I do not have a degree in Global Business, specializing in finance like Mr. Reiker. But I do have something I do not think Mr. Reiker has developed yet—an understanding of how utility investors in the real world think. To be blunt, I do not think any one can rationally conclude, no matter what Mr. Reiker's textbooks tell him, that an investor would ignore a water company's need to meet a draconian new arsenic standard, or threats to the utility's well fields, or the age and condition of its plant, in making investment decisions simply because the investor may have a diversified portfolio.

Q. ARE YOU BEING PAID FOR YOUR PARTICIPATION AS A WITNESS IN THIS PROCEEDING?

A. No, I am testifying because AUIA is very concerned about what we see as a dangerous trend that will ultimately weaken the viability of Arizona's utility industry. That trend, specifically, is the progressively lower equity returns being recommended by Staff based on financial theory rather than a well-reasoned consideration of all of the factors that impact the determination of a just and reasonable return.

II. INVESTOR CONSIDERATIONS

Q. HAVE YOU PERSONALLY PURCHASED AND SOLD COMMON STOCK OR OTHER EQUITY INSTRUMENTS?

A. Certainly, both in and outside the utility arena. Currently, I own stock in several utilities that do business in Arizona.

Q. IN YOUR POSITION WITH AUIA, HAVE YOU DISCUSSED INVESTING IN COMMON STOCKS OF UTILITIES AND/OR OTHER CORPORATIONS?

A. Yes. Investment in stock, particularly stock in utilities, is the foundation of AUIA's existence. In order to represent the interests of AUIA's members, I have developed a good working knowledge of the utility industry and, specifically, investment related matters.

Q. ARE YOU FAMILIAR WITH THE CRITERIA THAT A TYPICAL INVESTOR MIGHT CONSIDER WHEN EVALUATING WHETHER TO INVEST IN THE STOCK OF A UTILITY?

A. I believe I am. At the outset, it may be useful to distinguish between institutional and retail investors. Today, between 60 and 80 percent of the outstanding shares of some utilities are held by institutional investors, such as pension plans and investment trusts. Of the remainder, half or more may be held in "street" name by broker-dealers and the rest are shareholders of record on the corporate books.

Although all investors should in theory employ similar investment criteria, some have access to more information than others. A careful investor evaluating whether to invest in a utility would examine several factors such as liquidity and cash flows, capital structure, customer growth, capital requirements, return on equity, PE ratio, projected earnings and dividend growth and regulatory risk in addition to specific business conditions. Some institutional investors are prohibited from investing in a company that doesn't pay a dividend.

Retail investors may or may not have professional investment advisors, but should be interested in the same company-specific data and factors, although their analysis is typically less complex. Since many are at or near retirement age, they are in the "fixed-income" syndrome; they want safety along with consistent growth in earnings and dividends. People in this category often do not have the option of diversification and will have a "portfolio" of three or four dividend paying stocks.

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF STAFF WITNESS JOEL M. REIKER FILED IN THIS DOCKET?

A. Yes. Candidly, it is Mr. Reiker's testimony that led me to decide to testify for Arizona Water. For example, on page 7 of his direct testimony, Mr. Reiker states that:

> Risk is defined in modern portfolio theory as the sensitivity of an investment's returns to market returns. The most prevalent measure of risk is "beta." Beta is the measurement of an investment's market risk, and it reflects both the business risk and financial risk of a firm.

Q. ARE YOU FAMILIAR WITH THE TERM "BETA"?

A. Yes, I am familiar with the term "beta" as a tool for measuring the market risk of an investment. In my experience, an investor, at least a prudent one voluntarily making investment decisions, will not rely solely on a beta in making investment choices, irrespective of how diversified his portfolio might be.

Q. WHAT DO YOU VIEW AS THE PROBLEMS ASSOCIATED WITH RELYING ON A BETA TO REPRESENT ALL OF THE RISKS ASSOCIATED WITH AN EQUITY INVESTMENT IN A FIRM?

A. To begin with, I disagree with Mr. Reiker's emphasis placed on beta and his failure to acknowledge that investors consider other data and factors in evaluating which stock to purchase. Next, from a practical standpoint, there are a number of different issues surrounding a beta as it is used in the Capital Asset Pricing Model or "CAPM." The CAPM relies on the assumption that all investors hold efficient portfolios and all such portfolios move in perfect lockstep with the market. Fine theoretically, but this is not reality. *See* Reiker Direct at 21, l. 11.

Further, the results being produced, while they may be theoretically sound, are suspect, from a common sense perspective. *See* Reiker Direct at 25, Tables 6 and 7. The CAPM historical data results in a return that is only 7.7% (and the constant growth DCF model used by Staff produces only 8.5% return on equity). I understand Arizona Water's last series of bonds had an interest rate over 8%. This projected return is substantially less than what water and gas companies are currently earning, and well below Value Line's projections for 2004 and the 2006 - 2008 time period. However, this very low return (and the 8.5% return produced by the DCF constant growth model) is averaged with the higher return of 11.1% to produce an average return using the CAPM of only 9.0%.

Again, simple common sense indicates that something is wrong with a model when it produces results that low. What will cause the average return on equity to decline that much? Mr. Reiker makes no attempt to explain what will cause this to occur. He simply accepts the result produced.

Q. IN YOUR EXPERIENCE, DOES A TYPICAL INVESTOR RELY PRIMARILY ON BETA IN EVALUATING THE RISKS ASSOCIATED WITH AN INVESTMENT IN A UTILITY'S STOCK?

A. Having reviewed Mr. Reiker's testimony, I would say that relying solely on a beta could lead to imprudent decision-making by investors. Mr. Reiker also testifies in his direct testimony (at 7):

> Unique risk, or microeconomic risk, is risk that can be eliminated by portfolio diversification, i.e., buying securities in portfolios. Unique risk is not measured by beta nor does it factor into the cost of equity because it can be eliminated through simple shareholder diversification. Unique risks are particular to an individual company or investment project. Investors who hold diversified portfolios do not worry about unique risk; therefore, it does not affect the cost of capital. Additionally, investors who choose to be less than fully diversified will not expect to be compensated for unique risk.

Any investor who completely ignores what Mr. Reiker terms "unique risk" is not going to be very successful in his investments, no matter how diversified his portfolio. I could recite a long list of companies engaged in electric distribution, generation, trading, gas transportation, telephone distribution, long distance, wireless communications, software development and semiconductor manufacturing that have fallen flat since 2000. If you were invested in those companies then, you were probably rich. If you are holding their stock today, along with California bonds, your portfolio is six feet under water.

I would submit that much of the investment loss associated with those companies was the result of the market's failure to recognize and act on "unique" risks that were present in their business plans and the regulatory regimes under which they operated.

Q. SO YOU DO NOT AGREE WITH MR. REIKER'S ASSERTIONS ABOUT HOW INVESTORS VIEW "UNIQUE RISK"?

A. No. I would like to meet these "investors" Mr. Reiker testifies about. Are there really investors who will say "I don't care about the financial impact of the EPA's new arsenic standards on my equity return because I also own stock in Disney and Pepsi?" Would these same investors, making investments in Arizona's regulated utilities, turn a blind eye to the return on equity this Commission authorizes? Capital is not unlimited and prudent investors who consider all their options are not

ARIZONA WATER COMPANY
PHOENIX

likely to ignore real life risks, as Mr. Reiker seems to believe.

Q. **DO YOU AGREE WITH MR. REIKER'S VIEW THAT THE RISK ASSOCIATED WITH A PARTICULAR FIRM IS "ELIMINATED" IF SECURITIES ARE PURCHASED IN PORTFOLIOS?**

A. Mr. Reiker makes that point in his direct testimony (at 7) and I do not agree. I would, instead, argue that the risk associated with purchasing a particular firm's securities can never be eliminated. Presumably, the various stocks in an investor's portfolio each presents its own specific set of risks, which could, in theory, be averaged to create an overall risk for that particular portfolio. However, each stock will have its own particular set of risks associated with it and I believe prudent investors consider those risks in deciding whether to buy or hold a particular security.

Q. **DO YOU BELIEVE THAT MR. REIKER IS CORRECT IN ASSERTING THAT "INVESTORS WHO HOLD DIVERSIFIED PORTFOLIOS DO NOT WORRY ABOUT UNIQUE RISK"?**

A. I think Mr. Reiker lacks experience as an equity investor. I know that Arizona utility companies and AUIA receive many inquires from analysts and investors about the probable effect of "unique" or specific risks, including the risk posed by regulatory decisions of this Commission.

I certainly do not ignore unique risks associated with a particular firm when I consider the purchase of that firm's stock simply because I hold a "diversified portfolio," whatever that means. After all, I am not of unlimited wealth and I have to do my homework to make sure I maximize my opportunities for returns on my investments. I respectfully suggest that Arizona Water's shareholders do the same thing when determining the level of investment to make in the Company.

That is the focus of my concern and the reason for my testimony. If this

Commission adopts Staff's "ivory tower" view of finance and economics, and authorizes unreasonably low rates of return, I fear that investment in Arizona's utility industry will suffer a sharp and ultimately devastating decline.

Q. DO YOU BELIEVE THAT FIRM-SPECIFIC RISK AFFECTS THE COST OF CAPITAL?

A. I certainly do. It is my understanding that in setting rates for utility service, the Commission must allow a utility, in addition to recovering its operating expenses, taxes and depreciation, an opportunity to earn a return that is equal to returns that are being earned on investments in other businesses that have corresponding risks. This is known as the comparable earnings standard, and it has been in effect for decades. For example, in the *Bluefield Waterworks* case, decided in 1923, the United States Supreme Court stated: "A public utility is entitled to such rates as will permit it to earn a return . . . equal to that generally being made at the same time and in the same general part of the country on investments and other business undertakings which are attended by corresponding risks and uncertainties . . . ." *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692 (1923).

In another important decision, *Hope Natural Gas,* the United States Supreme Court re-emphasized the rate of return principles stated in *Bluefield Waterworks:* "The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

In order to apply the comparable earning standard, it is necessary to evaluate the firm-specific or unique risks associated with an investment in that particular firm. From the standpoint of a typical investor, I believe that Mr. Reiker violates this standard by choosing to ignore firm-specific risks and relying instead on <u>Value</u>

Line betas and the utilities' capital structures as the sole determinants of risk.

Q. WHAT SORT OF DATA AND INFORMATION MIGHT A TYPICAL INVESTOR CONSIDER IN EVALUATING THE RISKS ASSOCIATED WITH INVESTMENT IN A PARTICULAR FIRM'S STOCK?

A. Again, as I outlined previously, a typical investor would consider a variety of financial and non-financial factors and circumstances in evaluating whether to purchase a firm's stock. A good way of illustrating this point is to consider the information that is published by Value Line on the water utility industry and on certain publicly traded water companies. Mr. Reiker has presumably reviewed this information since he has used the betas from Value Line in preparing his testimony. *See* Schedule JMR-5. Value Line provides a variety of historical and projected financial data for each of the publicly traded water utilities that it follows, as well as a discussion of various firm-specific and industry-wide events. Applying Mr. Reiker's logic, however, all of this financial data and other information is simply irrelevant and ignored by investors. There would be no reason for Value Line and other investment services to gather and publish this information, nor would there be any market for this information, if investors didn't consider it in making investment decisions.

Q. STAFF IS RECOMMENDING A RETURN ON EQUITY OF ONLY 9.0% FOR ARIZONA WATER. HOW DOES THAT RETURN COMPARE TO THE RETURNS ON EQUITY BEING REPORTED BY THE PUBLICLY TRADED WATER UTILITIES USED IN STAFF'S SAMPLE?

A. Staff's sample contains six publicly traded utilities. According to the information reported in C. A. Turner Utility Reports (July 2003), these companies are currently earning a return on equity of, on average, 10.6%. Of course, it should be obvious that these comparable companies are larger than Arizona Water, meaning an investor is, at least based on that factor, going to view the comparable companies as less risky.

Q. BOTH ARIZONA WATER'S COST OF EQUITY WITNESS AND MR. REIKER HAVE ALSO USED A GROUP OF NATURAL GAS COMPANIES. WHAT RETURNS ON EQUITY ARE THOSE UTILITIES CURRENTLY REPORTING?

A. Arizona Water's expert has used eight natural gas companies that have A bond ratings. According to C. A. Turner, the average return on common equity for that group of eight gas companies is 11.66%.

Mr. Reiker has added two other gas utilities to the group, Cascade Natural Gas and Southwest Gas. Both of those gas companies have BBB bond ratings and are currently reporting very low returns on equity, according to C. A. Turner. Cascade Natural Gas is reporting a return on common equity of only 6.7% while Southwest Gas, which is the largest natural gas supplier in Arizona, is reporting a return on common equity of only 4.4%. If those two gas utilities are included in the average, the average return on equity drops to 10.44%, which is still nearly 150 basis points above what the Staff is recommending for Arizona Water in this case.

Mr. Reiker does not discuss the current returns on equity being reported by either sample group of publicly traded utilities. Are those returns on equity relevant to investors? I would think they are and, at a minimum, I would have expected Mr. Reiker to explain why the models he is using are producing results substantially below current returns on equity.

Q. AS YOU INDICATED, A SIGNIFICANT PORTION OF SOUTHWEST GAS' BUSINESS IS IN ARIZONA AND SOUTHWEST GAS IS CURRENTLY REPORTING THE LOWEST RETURN ON EQUITY OF ALL OF THE PUBLICLY TRADED UTILITIES. DO YOU HAVE ANY

COMMENT?

A. I am on record in that docket in opposition to the Commission's decisions regarding rates and commodity charges. However, I should note that Southwest Gas was granted rate increases in Decision No. 64172 (October 30, 2001) and that the return on equity approved for Southwest Gas in that decision was 11.0%, 200 basis points higher than the equity return being recommended for Arizona Water by Staff.

Q. DOES THE NATURE OF REGULATION IMPACT AN INVESTOR'S PERCEPTION OF THE RISK ASSOCIATED WITH A PARTICULAR UTILITY STOCK?

A. Yes. A public utility commission can have a significant impact on the investment risk associated with a particular utility stock. I am sure Commission-watchers will recall the unintended impact on the stock price of Pinnacle West Capital Corporation just a few years ago after an offhand comment by a Commissioner, as well as the general impact years of deregulation proceedings have had on Pinnacle West shares. Now, I am not suggesting that the Commission should avoid taking actions simply because it could impact the risk associated with an investment in a utility it regulates. Nevertheless, if the Commission authorizes a rate of return below that currently being earned by other utilities, it will be more difficult for the utility to raise capital, bond ratings may be reduced, etc. These factors, some might call "regulatory risk," are not ignored by investors. In fact, the May 2003 Value Line specifically mentions that regulatory decisions and policies in California are adversely impacting water utilities in that state.

Q. DOES THE NEW MAXIMUM CONTAMINANT LEVEL ("MCL") FOR ARSENIC, RECENTLY ESTABLISHED BY THE ENVIRONMENTAL PROTECTION AGENCY UNDER THE SAFE DRINKING WATER ACT,

CREATE ADDITIONAL RISK?

A. Yes, this is a good example of a firm-specific risk that an investor is going to consider, notwithstanding the theory relied on by Mr. Reiker.

Q. BUT DOESN'T STAFF ARGUE THAT THE NEW MCL FOR ARSENIC IS NOT A FIRM-SPECIFIC RISK BECAUSE IT IMPACTS THE ENTIRE WATER UTILITY INDUSTRY?

A. Yes, Mr. Reiker discusses this point in his direct testimony (at 57). Again, he claims that this is simply a unique risk and would not be "priced by the market." Moreover, Mr. Reiker does not discuss, and there is no indication that he has investigated, whether the six publicly traded water utilities have arsenic in their water supplies and, if so, how much they will be required to spend to comply with the new EPA requirement. He simply assumes, without any basis, that all water utilities will be impacted in the same way.

The AUIA has intervened in Arizona Water's Northern Group (Phase II) proceeding in which the Company is seeking to recover expenses associated with having to construct and operate new arsenic treatment facilities. Arsenic mitigation will be a very expensive undertaking for Arizona Water. According to the testimony filed in that docket, the Company anticipates having to finance nearly $30 million of arsenic treatment facilities and related plant, and faces increases in annual operating expenses of approximately $5 million over the next four years. These costs are very significant and, without rate relief, will have a significantly adverse impact on Arizona Water's earnings and financial viability. A prudent investor would certainly take these circumstances into account in deciding whether to invest in Arizona Water Company. Moreover, without some mechanism to assure insurance companies or other candidates for Arizona Water's bonds that there will be timely rate relief, I would expect it to be difficult for the Company to borrow funds at a reasonable cost, which would also adversely impact both the Company and its customers.

Q. DOES ARIZONA WATER'S RELATIVELY SMALL SIZE AFFECT THE RISKINESS OF AN INVESTMENT IN ITS COMMON STOCK?

A. From the standpoint of a typical investor, the answer is yes. I note that Mr. Reiker spends a substantial portion of his direct testimony attempting to disprove several studies that the Company's expert has provided to demonstrate that the size of a company does affect its investment risk. Common sense suggests that Mr. Reiker is simply wrong. A relatively small utility with a limited customer base and smaller revenue stream is more susceptible to adverse impacts resulting from circumstances like the new MCL for arsenic. Also, it is often more difficult for potential investors to find objective information about smaller companies because securities analysts don't follow them.

By contrast, a relatively large utility like Philadelphia Suburban, which is reported in C. A. Turner to have operating revenue in excess of $330 million and net utility plant in excess of $1.5 billion, and which operates in multiple jurisdictions, is likely to be less affected by new regulatory requirements or other unanticipated events. I would also note that Philadelphia Suburban is reporting a return on common equity of 14.0% – some 500 basis points higher than Mr. Reiker and Mr. Rigsby are recommending be authorized for Arizona Water, a smaller and more risky utility.

Q. SO IS IT YOUR BELIEF THAT REGULATION ITSELF AFFECTS INVESTOR RISK?

A. Yes. As I discussed above, there are numerous examples of regulatory decisions impacting stock value, which obviously impact investor risk. Investors do consider these factors. I know I do and I am an investor.

Again, Arizona Water's proceeding related to the recovery of costs associated with arsenic treatment is a perfect example. Arizona Water is attempting to obtain approval of a mechanism that will allow it to timely recover costs and expenses. However, RUCO is opposing recovery of operating expenses outside of a general rate case and Staff, while initially opposing recovery of operating expenses, has agreed to allow some operating expenses to be recovered. Is it really Mr. Reiker's belief that an investor would not be concerned about Arizona Water's ability to earn a return on the enormous investment, relative to its size, required to construct arsenic treatment facilities or to recover increased operating expenses? If so, I again respectfully suggest that Mr. Reiker lacks an appreciation for the realities of the business world.

Regulatory lag is yet another example of risk associated with regulation that an investor is likely to consider. It typically takes 13 months or longer (it will be at least 16 months in this docket) to obtain rate relief in this jurisdiction. In addition, in a brief recently filed with the Arizona Court of Appeals, the Commission has indicated that a utility that has just obtained a decision from the Commission setting new rates must wait a full 12 months before filing a new rate application, which would dramatically increase the amount of regulatory lag in this jurisdiction. (*Arizona American Water Company v. Arizona Corporation Commission*, No. 1 CA-CC 03-0001, Commission Responsive Brief at 23.) While I disagree with Staff, this new "policy," which is not reflected in the Commission's rules or any decision, will most assuredly adversely impact investors' perception of the risk associated with an investment in Arizona Water as compared to other publicly-traded utilities, or any other available investment for that matter.

Q. BUT ACCORDING TO MR. REIKER, AREN'T SUCH RISKS ARE AMELIORATED BY DIVERSIFICATION?

A. That's what Mr. Reiker claims, but as explained above, I do not accept his theory. In fact, I can suggest another way to minimize or eliminate these types of risks – not make the investment in the first place, which I fear is the result we are going to see if Staff's attempt to drive down equity returns is accepted by the Commission.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

REBUTTAL TESTIMONY & EXHIBITS

OF

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS EASTERN GROUP AND FOR CERTAIN RELATED APPROVALS.	Docket No. W-01445A-02-0619

REBUTTAL TESTIMONY OF MICHAEL J. WHITEHEAD

Table of Contents

I. INTRODUCTION AND QUALIFICATIONS

Q. WHAT IS YOUR NAME, EMPLOYER AND OCCUPATION?

A. My name is Michael J. Whitehead. I am employed by Arizona Water Company (the "Company") as Vice President of Engineering.

Q. ARE YOU THE SAME MICHAEL J. WHITEHEAD THAT PREVIOUSLY GAVE DIRECT TESTIMONY IN THIS MATTER?

A. Yes.

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY FILED BY THE OTHER PARTIES TO THIS PROCEEDING?

A. Yes, I have reviewed the testimony of each witness for the Commission's Utilities Division Staff ("Staff") and RUCO and specifically analyzed the portions of the Staff and RUCO testimony concerning operational or engineering issues, including the post test year plant issues impacting the determination of the Company's fair value rate base.

II. PURPOSE AND EXTENT OF TESTIMONY

Q. WHAT IS THE PURPOSE AND EXTENT OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to explain the difference in the Company's original request for post test year plant additions, which request was based on the 2002 construction budget and several projects that were carried over from previous years, and the current level of post test year plant additions, which includes revenue-neutral projects actually completed as of December 31, 2002.

I will also provide and discuss the Company's present schedule for the interconnection of Apache Junction and Superior systems to address Mr. Hammon's argument that there is no known timeline for the physical interconnection of the two systems. *[Hammon Direct Testimony, page 11, line 26;*

page 12, lines 1-21 I will also discuss the Company's proposed rate design consolidation of the two systems which should occur now instead of sometime in the future.

III. REBUTTAL CONCERNING POST TEST YEAR PLANT ADDITIONS

Q. WHAT DID STAFF AND RUCO RECOMMEND WITH RESPECT TO THE COMPANY'S PROPOSED POST TEST YEAR PLANT ADDITIONS?

A. Staff accepted the Company's position that those construction projects funded by the Company and completed and placed in service prior to December 31, 2002 may be included in the Rate Base. *[Ludders Direct Testimony, page 6, lines 6-19; Hammon Direct Testimony, page 7, lines 14-19]* These post test year plant additions are non-revenue producing, that is, they consist of wells, reservoirs, transmission lines and other construction projects that improve service to customers existing at the end of the test year, as opposed to providing service to new customers. RUCO, included all 2002 plant additions and retirements consistent with its overall recommendation to use an unadjusted historical test year. *[Coley Direct Testimony, page 19, lines 14-22]*

When the Company filed its 2002 Rate Case for the Eastern Group, the actual construction costs for the proposed post test year plant additions were not known. The Company's initial estimated costs for post test year plant additions were taken from its 2002 construction budget, along with those projects where construction was started prior to 2001 and that were scheduled to be completed and placed in service prior to December 31, 2002. Column 1 of Exhibit MJW-R1 (attached hereto at Tab 1) summarizes the actual construction expenditures included in the Company's post test year plant additions as of the initial application.

The construction expenditures detailed on Exhibit MJW-R1 are broken down by system, specific project (work authorization number), and blankets. It should be noted that not all scheduled construction projects were completed by December 31, 2002 and some projects were cancelled. Those projects that were either cancelled or not completed by December 31, 2002 should not be included in the post test year plant additions and the Company is adjusting its requested level of post test year plant additions to remove those cancelled and incomplete projects. Column 2 of Exhibit MJW-R1 (Tab 1) reflects the Company's revised request for post test year plant additions.

Q. DID STAFF AND RUCO VERIFY THE COMPANY'S POST TEST YEAR ADDITIONS?

A. Yes. On January 20, 2003 Mr. Hammon conducted a field inspection of the Company's Winkelman, San Manuel, and Oracle systems followed by a field inspection of the Company's Bisbee and Sierra Vista systems on January 21, 2003, the Superior and Miami systems on January 22, 2003 and the Apache Junction system on January 27, 2003.

On January 6, 2003 RUCO, represented by William A. Rigsby and Timothy J. Coley, made a field inspection of the Apache Junction, Miami, and Superior systems followed by a field inspection of the Company's Winkelman, San Manuel, and Oracle systems on January 9, 2003 and the Bisbee and Sierra Vista systems on January 10, 2003.

The Division Managers and I were present at both Staff's and RUCO's field inspections. Both Staff and RUCO specifically asked to see and verified that all of the projects included in the Company's post test year plant additions were in service and serving existing customers as of December 31, 2002.

IV. CONSOLIDATION OF APACHE JUNCTION AND SUPERIOR SYSTEMS

Q. IN HIS DIRECT TESTIMONY, MR. HAMMON RECOMMENDED THAT THE CONSOLIDATION OF THE TWO SYSTEMS FOR RATE MAKING

PURPOSES SHOULD BE POSTPONED BECAUSE THERE IS NO KNOWN TIMELINE FOR THE PHYSICAL INTERCONNECTION OF THE APACHE JUNCTION AND SUPERIOR SYSTEMS. WOULD YOU PLEASE DISCUSS THE PROPOSED APACHE JUNCTION AND SUPERIOR INTERCONNECTION AND PROVIDE AN UP-TO-DATE TIMELINE FOR THE INTERCONNECTION?

A. The first step to interconnecting the Apache Junction system to the Superior system is the installation of four and one-half (4-1/2) miles of sixteen-inch (16") transmission main to serve Entrada del Oro.[1] The sixteen-inch (16") transmission line will be installed within an existing electrical power line corridor extending from Gold Canyon to the Entrada del Oro development. This pipeline is under construction and is scheduled to be completed by year-end 2003. The first phase (approximately 150 residential units) of the on-site water distribution system to serve Entrada del Oro is also scheduled to be completed by year-end 2003.

A 750 unit subdivision called Ranch 160 is located along the northern edge of the Apache Junction CC&N at Florence Junction, approximately one and one-half (1-1/2) miles south of Entrada del Oro. The first phase of providing water service to Ranch 160 included drilling two deep wells within the development and was completed last year. The on-site distribution system to serve the first 75 units of Ranch 160 is scheduled to be completed during 2003. The Company allocated funds in its 2003 construction budget to construct the necessary pipelines to interconnect Entrada del Oro to Ranch 160 and interconnect Ranch 160 to the

[1] On December 26, 2001 the Company filed an Application with the Commission to extend its CC&N from Gold Canyon to the Apache Junction CC&N at Florence Junction. This Application was made at the request of Grosvenor Holdings L.L.C. so that the Company could provide water service to Grosvenor's proposed 1,055 lot subdivision called Entrada del Oro. The Commission hearing for the proposed CC&N extension was held on July 24, 2003. Staff is recommending approval of the Company's Application to extend its CC&N physically interconnecting the Apache Junction and Superior systems.

Superior well field, located four (4) miles to the south.

Subject to right-of-way clearance and acquisition of easements, the Company anticipates that the Entrada del Oro development will be interconnected to the Ranch 160 development and that the Ranch 160 development will be interconnected to the Superior well field within two years. Once these final two interconnects are made, the Apache Junction and Superior systems will be fully interconnected and both systems will benefit by sharing storage facilities, well production, treatment costs for arsenic, and all other benefits associated with a large, integrated system.

Consequently, the time to consolidate the Apache Junction and Superior systems for rate making purposes is now, during this rate case for the Company's Eastern Group, since the two systems will be interconnected within two years. Consolidating the two systems in this rate proceeding also will provide all interested parties an opportunity to participate in rate design. Assuming the Arsenic Cost Recovery Mechanism is applied to the Eastern Group, consolidating the Apache Junction and Superior rates now will eliminate rate design issues in that proceeding.

Q. MR. WHITEHEAD HAS TESTIFIED THAT APACHE JUNCTION AND SUPERIOR WILL BE INTERCONNECTED WITHIN TWO YEARS. WHAT HAPPEN IF THESE SYSTEMS ARE NOT COMBINED FOR RATE PURPOSES NOW IN THE TWO STEP PROCEDURE RECOMMENDED BY THE COMPANY?

A. Based on the Company's original request Apache Junction revenues would have to increase 16.7%, on a stand-alone basis, and Superior's would have to increase 71.4%. Since these systems will be interconnected before the next general rate application, beginning the eventual rate consolidation now, in the two step procedure the Company recommends, offers at least two distinct advantages. First, by consolidating the minimums now and the commodity rates in the next proceeding, the required revenue increase for Superior can be reduced from 71.4% to 8.9%. This is achieved with less than a 6% additional increase in Apache Junction's revenue requirement from 16.7% to 22.2%. Second, the Company's two-step-proposal would move the rates of each system closer together now rather than driving the existing stand alone rates even further apart as Staff and RUCO recommend. This gradual approach would simplify and minimize the consolidation impact in the next rate proceeding.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY IN THIS MATTER?

A. Yes, it does, except that I wish to note that my silence on any issue raised or recommendation made by Staff or RUCO should not be taken as the Company's acceptance of such issue or recommendation.

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EXHIBITS

Arizona Water Company
Docket No. W-01445A-02-0619
Eastern Group Post Test Year Plant Additions
Test Year 2001

Line	Work Auth. #	Description	AWC's Original Post Test Year Plant Additions (8/14/02 Filing)	Actual Post Test Year Plant Additions 12/31/2002
(a)	(b)	(c)	(d)	(e)
	Apache Junction			
1	Blankets	Multiple small projects each amounting to less than $5,000.	$684,975	$620,467
2	1-2551	Retention basin for new Well #16.	52,652	49,155
3	1-2975	Install 15,800 LF of 12" DIP from Florence Junction well field to Ranch 160 and tie-in main.	368,564	Carryover
4	1-2976	Purchase well site and drill and equip new well.	579,172	Carryover
5	1-2981	Pull and replace pump assembly at Well #12.	19,255	54,981
6	1-2982	Provide preliminary engineering study for office/warehouse expansion.	6,133	6,081
7	1-3167	Replace 8" gate valve at Ironwood and Apache roads.	14,970	13,647
8	1-3210	Purchase well site and drill and equip new well.	684,476	Carryover
9	1-3211	Install transmission main to move water from west to east part of the system.	526,520	Carryover
10	1-3212	Install 1,850 LF of 6" DIP to replace existing 2" steel pipe.	162,089	145,575
11	1-3213	Reconstruct existing tank overflow lines at University, Oasis, Superstition, & County Line tank sites.	26,326	44,254
12	1-3214	Rebuild Oasis Tank booster pump station.	131,630	Carryover
13	1-3215	Pull and replace pump assembly at Oasis Well #13.	51,084	59,785
14	1-3216	Pull and replace booster pump assembly at Superstition Tank site.	7,817	22,894
15	1-3217	Upgrade the booster pump station at Superstition Tank site.	66,874	Cancelled
16	1-3218	Replace two services at Thunder Mountain Middle School and one at Trails West Mobile Home Park.	89,508	62,095
17	1-3317	Abandon 330 LF of 6" pipe on Superstition Blvd. for AJ Fire Station #2 improvements.	12,089	17,207
18	1-3318	Install 16"x6" TS&V and tie-in 6" main to the 16" main on Tomahawk Road, south of East Second Avenue.	12,489	18,382
19	1-3322	Pull and replace pump and motor at Well 14.		34,518
20	1-3347	Abandon 8" and 6" C.A. pipe and relocate with 8" DIP;		Carryover
		Subtotal Apache Junction	$3,496,624	$1,149,041
		Plus: Phoenix & Meter Shop Allocation	$256,722	$130,939
		Total Apache Junction	$3,753,346	$1,279,981
	Bisbee			
1	Blankets	Multiple small projects each amounting to less than $5,000.	$95,565	$67,492
2	1-3219	Drill and equip 1,000 ft by 16" cased well.	394,890	659,419

Arizona Water Company
Docket No. W-01445A-02-0619
Eastern Group Post Test Year Plant Additions
Test Year 2001

Line	Work Auth. #	Description	AWC's Original Post Test Year Plant Additions (8/14/02 Filing)	Actual Post Test Year Plant Additions 12/31/2002
(a)	(b)	(c)	(d)	(e)
3	1-3311	Abandon and relocate 4" and 2" pipe with 250 LF of 8" DIP and 120 LF of 6" DIP down Spring Canyon.	50,255	41,830
4	1-3356	Pull and replace the pump for Booster #5-NACO.		17,515
		Subtotal Bisbee	$540,711	$786,256
		Plus: Phoenix & Meter Shop Allocation	$56,832	$28,987
		Total Bisbee	$597,543	$815,243
	<u>Sierra Vista</u>			
1	Blankets	Multiple small projects each amounting to less than $5,000.	$58,440	$33,654
2	1-3220	Replace 40 plastic services at various locations.	52,652	50,435
3	1-3221	Replace booster pump at the Fuller Yard.	18,428	22,286
		Subtotal Sierra Vista	$129,520	$106,376
		Plus: Phoenix & Meter Shop Allocation	$31,037	$15,830
		Total Sierra Vista	$160,557	$122,206

Arizona Water Company
Docket No. W-01445A-02-0619
Eastern Group Post Test Year Plant Additions
Test Year 2001

Line	Work Auth. #	Description	AWC's Original Post Test Year Plant Additions (8/14/02 Filing)	Actual Post Test Year Plant Additions 12/31/2002
(a)	(b)	(c)	(d)	(e)
	Miami			
1	Blankets	Multiple small projects each amounting to less than $5,000.	$68,593	$124,265
2	1-3027	Abandon 1,400 LF of 6" CA and install 1,452 LF of 6" DIP from Central Heights Road to SPRR right of way south of Highway 60.	92,007	103,436
3	1-3193	Pull and replace pump assembly at Well #18.	15,473	14,845
4	1-3249	Install 11 ladder safety systems at all storage tanks.	9,477	Cancelled
5	1-3250	Replace 1,270 LF of 6" pipe with 8" DIP on Highway 60 from Third Street and the alley behind Claypool Yard.	88,936	85,949
6	1-3251	Install MOSCAD RTU and programming for warehouse and tank sites.	33,284	30,696
7	1-3252	Install chlorinators at wells 20 and 25.	30,538	Cancelled
8	1-3253	Replace 800 LF of 1" with 1,250 LF of 6" DIP on Highway 88, south of Mineral Lane in Bandy Heights.	57,153	60,069
9	1-3254	Replace 30 services of various sizes.	52,592	41,726
10	1-3350	Pull and replace pump and motor at Well 26.		15,157
		Subtotal Miami	$448,054	$476,144
		Plus: Phoenix & Meter Shop Allocation	$52,927	$26,995
		Total Miami	$500,981	$503,139
	San Manuel			
1	Blankets	Multiple small projects each amounting to less than $5,000.	$18,561	$21,915
2	1-2791	Relocate voice radio base station from San Manuel to Oracle Town Tank.	21,839	22,089
3	1-3030	Replace pressure regulator on Avenue A and 6th Avenue.	22,970	24,289
4	1-3255	Replace booster pump and install in a new vault.	14,743	Carryover
		Subtotal San Manuel	$78,112	$68,293
		Plus: Phoenix & Meter Shop Allocation	$21,479	$10,955
		Total San Manuel	$99,591	$79,248
	Oracle			
1	Blankets	Multiple small projects each amounting to less than $5,000.	$25,587	$42,938
2	1-3031	Parallel 2,640 LF of 8" CA with 12" DIP on abandoned Highway 77.	108,388	102,012
3	1-3033	Replace pressure regulating station at Rockcliffe Blvd and State Highway 77.	22,914	23,868
4	1-3256	Parallel 2,640 LF of 8" transmission main with 12" DIP along State Highway 77.	100,039	Carryover

Arizona Water Company
Docket No. W-01445A-02-0619
Eastern Group Post Test Year Plant Additions
Test Year 2001

Line	Work Auth. #	Description	AWC's Original Post Test Year Plant Additions (8/14/02 Filing)	Actual Post Test Year Plant Additions 12/31/2002
(a)	(b)	(c)	(d)	(e)
5	1-3257	Replace pump house at Booster #2.	30,538	33,327
6	1-3281	Relocate 350 LF of 4" CA with 6" DIP in an easement east of Cody Loop Road.	17,132	22,396
		Subtotal Oracle	$304,598	$224,541
		Plus: Phoenix & Meter Shop Allocation	$26,309	$13,419
		Total Oracle	$330,907	$237,960
	Winkelman			
1	Blankets	Multiple small projects each amounting to less than $5,000.	$7,765	$12,642
2	1-3258	Paint and repair Winkelman yard.	6,318	Cancelled
3	1-3352	Pull and replace pump and motor at Well No. 4.		8,899
		Subtotal Winkelman	$14,083	$21,541
		Plus: Phoenix & Meter Shop Allocation	$3,083	$1,573
		Total Winkelman	$17,166	$23,114

Arizona Water Company
Docket No. W-01445A-02-0619
Eastern Group Post Test Year Plant Additions
Test Year 2001

Line (a)	Work Auth. # (b)	Description (c)	AWC's Original Post Test Year Plant Additions (8/14/02 Filing) (d)	Actual Post Test Year Plant Additions 12/31/2002 (e)
		Superior		
1	Blankets	Multiple small projects each amounting to less than $5,000.	$39,177	$45,236
2	1-3268	Replace 800 LF of 8" steel with 8" DIP to continue the Heiner Road project.	47,178	44,534
3	1-3269	Replace 2,050 LF of 8" steel pipe with 8" DIP along Highway 177 from Lobb Avenue to Terrace Drive.	193,164	186,333
		Subtotal Superior	$279,520	$276,103
		Plus: Phoenix & Meter Shop Allocation	$24,357	$12,423
		Total Superior	$303,877	$288,526
		Phoenix		
1	Blankets	Multiple small projects each amounting to less than $5,000.	$78,978	$67,823
2	1-2608	Upgrade communication lines between Data Processing department and division offices.	101,161	90,838
3	1-2815	Programming and training to upgrade ITRON meter reading to Windows.	56,201	Carryover
4	1-3057	Upgrade AS400 Model 500 to Model 700 with integrated NT processor.	70,598	80,347
5	1-3062	Convert the Rate Case from Lotus to Excel.	44,603	42,205
6	1-3270	Construct office addition.	452,807	Carryover
7	1-3271	Consulting and programming in Data Processing department.	166,605	197,001
8	1-3272	Purchase office furniture and equipment for accounting.	19,481	Carryover
9	1-3273	Purchase four PCs for Engineering department.	7,539	7,636
10	1-3274	Purchase an OCE TDS 400 copier, plotter and scanner system for Engineering department.	29,211	30,104
		Total Phoenix	$1,027,184	$515,953
		Meter Shop		
1	Blankets	Multiple small projects each amounting to less than $5,000.	$527	$8,224
		Total Meter Shop	$527	$8,224
		Subtotal Excluding PX & MS	$5,291,222	$3,108,295
		PX & MS (Total $1,027,710 (Orig.); $515,953-(Actual) Eastern Group Allocation	472,746	241,121

Arizona Water Company
Docket No. W-01445A-02-0619
Eastern Group Post Test Year Plant Additions
Test Year 2001

Line	Work Auth. #	Description	AWC's Original Post Test Year Plant Additions (8/14/02 Filing)	Actual Post Test Year Plant Additions 12/31/2002
(a)	(b)	(c)	(d)	(e)
		Total Eastern Group PTYPA	$5,763,968	$3,349,416

ARIZONA WATER COMPANY

Docket No. W-1445A-02-0619

2002 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/01

PREPARED

REBUTTAL TESTIMONY & EXHIBITS

OF

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS NORTHERN GROUP AND FOR CERTAIN RELATED APPROVALS.	Docket No. W-01445A-02-0619

REBUTTAL TESTIMONY OF THOMAS M. ZEPP

Table of Contents

I. INTRODUCTION, SUMMARY AND CONCLUSIONS

Q. PLEASE STATE YOUR NAME.

A. Thomas M. Zepp.

Q. DID YOU PREPARE DIRECT TESTIMONY ON BEHALF OF ARIZONA WATER IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. Arizona Water Company ("Arizona Water" or "the Company") asked me to update my testimony and to review and to respond where I thought it to be appropriate to the July 8, 2003 testimonies of Mr. Joel M. Reiker on behalf of the Arizona Corporation Commission Staff and Mr. William A. Rigsby on behalf of the Residential Utility Consumer Office ("RUCO").

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In this section of my testimony, I summarize my conclusions. In Section II, I present an update of my direct testimony. In making my updates I respond to some of the comments Mr. Reiker and Mr. Rigsby made about the approaches and samples I adopted to make those estimates. In Section III, I respond to Mr. Reiker and Mr. Rigsby's contention that smaller water utilities do not have higher equity costs than larger water utilities. As part of that discussion, I present my article that is forthcoming in *The Quarterly Review of Economics and Finance* that addresses this issue. Given the various systematic risks faced by Arizona Water, I conclude the Company requires a 100 to 150 basis point risk premium above benchmark equity cost estimates made with data for the publicly-traded utilities. In Section IV, I respond to Mr. Reiker and Mr. Rigsby's equity cost estimates made with the capital asset pricing model ("CAPM"). I restate their analyses using long-term Treasury rates. In Section V, I comment about the methods Mr. Reiker has taken to make DCF equity cost estimates. I restate his constant growth DCF model results with more appropriate growth rates and revise his multi-stage DCF model by incorporating his estimates of intrinsic growth. Finally, I present an average of his restated CAPM and DCF equity cost estimates. In Section VI, I present Mr. Rigsby's DCF equity cost estimates with restated estimates of VS growth. In this section I also present a summary of my restatements of Mr. Reiker and Mr. Rigsby's DCF and CAPM approaches.

Q. DO YOU SPONSOR ANY SCHEDULES AND EXHIBITS TO ACCOMPANY THIS REBUTTAL TESTIMONY?

A. Yes. I have prepared 15 tables, attached at Tab A, that update my testimony; 12 new rebuttal tables, attached at Tab B, that respond to Mr. Reiker and Mr. Rigsby's contentions; and I sponsor 3 exhibits, including my article, attached at Tab C.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I provide rebuttal testimony to two primary topics: the cost of equity of publicly-traded water utilities and the magnitude of the equity risk premium above that benchmark equity cost estimate that is required to provide Arizona Water a fair rate of return on equity.

Mr. Rigsby and Mr. Reiker make no attempt to estimate the latter. They just take the position that the equity risk premium should be zero. As a threshold observation, such a position makes no sense when Arizona Water has been unable to issue debt at a cost as low as the A-rated and AA-rated water utilities used by Mr. Reiker and Mr. Rigsby to make their benchmark equity cost estimates. Mr. Reiker and Mr. Rigsby simply ignore this obvious and indisputable fact.

I also respond to Mr. Reiker's and Mr. Rigsby's position that size does not matter in the determination of utility risk and required returns. Mr. Reiker and Mr. Rigsby don't take issue with there being a small firm effect for stocks in general --

they just say the small firm effect does not apply to utilities. The primary "evidence" they offer to rebut the need for any premium is an article by Annie Wong. My recently accepted and peer-reviewed article rebuts Wong and shows that the best available evidence indicates there is a small firm effect for utilities as well as stocks in general.

Q. DO YOU RESPOND TO OTHER CRITICISMS MR. REIKER AND MR. RIGSBY MAKE OF YOUR ESTIMATED 100 TO 150 BASIS POINT RISK PREMIUM FOR ARIZONA WATER?

A. Yes. One of Mr. Reiker's contentions is that Arizona Water is less risky than the sample water utilities because it has a higher book equity ratio. In making such a statement, he ignores the fact that even though Arizona Water had an above-average common equity ratio when it issued its last debt issue, it nevertheless could not obtain a debt cost as low as the sample water utilities could have obtained at the time of issue. Mr. Reiker overlooks the obvious point that Arizona Water has business risk that overwhelms any risk-reducing benefit of less leverage. To make matters worse, Mr. Reiker gets fascinated with a technical "unlevered" versus "relevered" beta argument that he attempts to apply to Arizona Water. I point out that he fails in such an application because (1) he has no basis to assume (as he does) that Arizona has the same business risk as the sample companies used to determine beta estimates, (2) he uses the wrong measure of equity in applying the formula and (3) worse than the other points, he does not have a market value for Arizona Water that is required to make the calculation. This is a theory that cannot be applied to Arizona Water. It is like trying to force a square peg through a round hole. Since Mr. Reiker has made this totally inappropriate presentation in his testimony, I respond to it.

Mr. Reiker also contends that the only systematic risk of relevance to the determination of the cost of equity is "beta" when that is not the case. I offer a number of responses to him on that point, one of the most telling is that the author of the CAPM, Professor William Sharpe, says empirical research and other theoretical considerations justify consideration of more risks than beta. Obvious systematic risk candidates are distress risk and size that were found by Fama and French. And Arizona Water's risks of having to meet new EPA arsenic requirements and difficulties with obtaining rates that cover costs when there are limited out-of-period adjustments and opposition to automatic adjustment mechanisms to recover power and other operating costs are obvious candidates that fall in the systematic risk categories of "distress" and "size." These risks may well increase Arizona Water's beta (if one could be measured).

I also respond to Mr. Reiker's and Mr. Rigsby's contention that the January Effect and an article discussed by Mr. Rigsby justify ignoring the small firm effect for utilities. I explain why that such theories do not eliminate the need to recognize small size risk for Arizona Water.

Q. DO YOU REPOND TO MR. REIKER AND MR. RIGSBY'S ESTIMATES OF EQUITY COSTS FOR THE BENCHMARK SAMPLES OF WATER UTILITES?

A. Yes. Mr. Reiker and Mr. Rigsby make equity cost estimates for the benchmark water utilities that average 9.2% and 9.18% (9.2%), respectively. Such equity cost estimates – however they were made – lack perspective, perspective about what is a fair rate of return for the benchmark utilities. Rebuttal Table 1 provides that perspective. It shows that the utilities in Mr. Reiker's sample have been authorized ROEs that have averaged 173 basis points higher than the 9.2% rate of return that Mr. Reiker and Mr. Rigsby conclude is "fair". It also shows that those utilities have earned returns that average 144 basis points above the 9.2% recommendation and that Value Line forecasts of rates of returns two years into the future for water utilities in Mr. Rigsby's sample have averaged 170 basis points above the 9.2% ROEs Mr. Reiker and Mr. Rigsby recommend. This perspective in Rebuttal Table 1 shows that whatever the methods being used, whatever the theories being adopted, and whatever the assumptions being made by Mr. Reiker and Mr. Rigsby, the final ROE estimates being produced are nonsense. It is nonsense to claim that ROEs required by these sample utilities are so far below what they are actually making, actually being authorized and what Value Line is forecasting they will earn. Something is amiss. By contrast, my updated equity cost estimates for the benchmark water utilities fall in a range of 10.3% to 11.2% and are reasonable when compared to returns that are actually being made, authorized and forecasted for the publicly-traded water utilities. Also, my restatements of Mr. Reiker's and Mr. Rigsby's equity costs for the benchmark utilities fall in a range of 9.6% to 11.3% and thus also bracket the averages of authorized, earned and forecasted ROEs in Rebuttal Table 1.

Q. WHAT OTHER ISSUES DO YOU ADDRESS?

A. I also respond to the lengthy technical rebuttal of my testimony that Mr. Reiker has presented. While Mr. Reiker is highly critical of my direct testimony (which relied on data obtained in the summer of 2002) and in places has distorted my testimony, his discussion is flawed and ultimately erroneous in a number of significant respects, as I show below. For example, he argues I made an error by using an industry average forecast of growth when a reliable company-specific forecast was not available, but then turns around and uses such an industry forecast in Schedule JMR-6 to prepare his own estimates of growth when there are no reliable forecasts for some utilities. Mr. Reiker wants it both ways. He also claims I relied exclusively on analysts' forecasts of growth when I did not. He mischaracterizes my testimony being at odds with a paper by Professor Gordon when it is not. He takes a small cite from my testimony in a 1999 Oregon case out of context by claiming I advocated the use of dividend per share ("DPS") growth to make growth estimates for the constant growth DCF model when I did not. Mr. Reiker had my testimony and knew I did not propose such an approach. To support his choice of actual interest rates, Mr. Reiker argues that forecasts of interest rates by Blue Chip should not be adopted when his own Chart 4 shows such forecasts have been unbiased. Such forecasts are more relevant for the period when Arizona Water's new tariffs will be in place than are the current rates he adopts in his analyses. Mr. Reiker offered Chart 7 and 8 as rebuttal of my Tables 9 and 10 but compares a different time period to the one I addressed. Mr. Reiker also fabricates a 9% ROE estimate by carefully selecting data for one of the eleven years in my Table 8. Had he looked at all of the data in Table 8, he would have found the table he relied upon to create the fictitious 9% ROE estimate actually supports an ROE range for Arizona Water of 10.9% to 12.0%.

Mr. Reiker also criticizes the estimates I presented in Table 8 that support the small firm effect for water utilities. He chooses the wrong statistics test to increase the calculated uncertainty in my results. This choice of statistical test "allows" him to claim I have not demonstrated the small firm effect for water utilities. I provide a section from a statistics book to show he is wrong and the test he chose was inappropriate.

Q. WHAT ARE YOUR SPECIFIC CONCLUSIONS?

A. My conclusions are:

1. An update of my DCF and risk premium equity cost estimates indicate Arizona Water's cost of equity now falls in a range of 11.3% to 12.7%. See Rebuttal Table 16.

a) Updated DCF equity costs indicate a cost of equity range for Arizona Water of 11.6% to 12.3%.

b) Updated risk premium estimates indicate a cost of equity range for Arizona Water of 11.3% to 12.7%.

2. Appropriate restatements of Mr. Reiker and Mr. Rigsby's equity cost estimates indicate Arizona Water's cost of equity falls in a range of 10.6% to 12.8%. See Rebuttal Table 27.

3. No evidence provided by either Mr. Reiker or Mr. Rigsby shows that the 100 to 150 basis point risk premium I estimated in my direct testimony is inappropriate.

a) Arizona Water's cost for its most recent bond issue by itself justifies a risk premium of 37 to 49 basis points.

b) There is a small firm effect in the utilities industry. The best available evidence indicates Arizona Water's size alone justifies a risk premium adder of 99 basis points. My forthcoming article in *The Quarterly Review of Economics and Finance*, attached at Tab C, shows the Wong article Mr. Reiker and Mr. Rigsby relied upon to dismiss the small firm effect for Arizona Water does not provide a basis for such a dismissal.

c) Arizona Water faces other systematic risks related to changes in EPA requirements to remove arsenic and historical test periods with limited out-of-period adjustments that, combined with the risks mention in a) and b) justifies the 100 to 150 basis point adder.

II. UPDATES OF DIRECT TESTIMONY AND EXHIBITS

Q. HAVE YOU UPDATED THE EQUITY COSTS IN YOUR DIRECT TESTIMONY?

A. Yes.

Q. WHAT IS YOUR UPDATED DCF EQUITY COST FOR THE SAMPLE OF WATER UTILITIES AND ARIZONA WATER?

A. The updated DCF equity cost for the sample of water utilities is 10.8%. In making that estimate I have adopted an average of dividend yields during the three month period ending May 31, 2003. This period of time overlaps the 8-week period Mr. Rigsby adopts to determine dividend yields and contains the spot price adopted by

Mr. Reiker to make his dividend yield estimates. That DCF equity cost estimate is shown on Rebuttal Table 6 and is based on the data presented in Rebuttal Tables 2 through 5. Neither Mr. Rigsby nor Mr. Reiker provide any convincing evidence to reduce the 100 to 150 basis point risk premium adder for Arizona Water that I developed in my direct testimony, thus Arizona Water has an equity cost range of 11.8% to 12.3% based on this updated DCF equity cost estimate.

Q. **WHAT IS YOUR UPDATED EQUITY COST ESTIMATE FOR THE PUBLICLY-TRADED WATER UTILITIES THAT YOU MADE WITH DATA FOR THE GAS UTILITIES?**

A. With the updated data, I estimate the equity cost for the gas utilities sample is 10.6% and Arizona Water's equity cost falls in a range of 11.6% to 12.1%. These equity costs are developed in Rebuttal Tables 8 to 12.

Q. **HAVE YOU UPDATED YOUR RISK PREMIUM ANALYSES?**

A. Yes. Rebuttal Tables 13, 14 and 15 provide updates of Table 22, 23 and 24 in my direct testimony. All of those risk premium equity cost estimates have dropped because the forecasts of Baa rates are now lower than they were last year. Based on the updated risk premium analyses, Arizona Water has an equity cost that now falls in a range of 11.3% to 12.7%. See Rebuttal Table 16.

Q. **DO MR. REIKER AND MR. RIGSBY CRITICIZE YOUR ESTIMATES?**

A. Yes. Both Mr. Reiker and Mr. Rigsby criticize development of my estimate of the 100 to 150 basis point adder to benchmark cost of equity estimates that Arizona Water requires. I respond to their testimony is Section III. Mr. Rigsby provides his own DCF estimates but does not make specific criticisms of mine. Mr. Reiker criticizes (1) the samples of gas and water utilities I used to make benchmark equity cost estimates, (2) the method I used (and Mr. Rigsby used) to compute dividend yields, (3) my estimates of growth used in the constant growth DCF model and (4) my risk premium estimates.

Q. **PLEASE TURN TO MR. REIKER'S COMMENTS ABOUT THE SAMPLES YOU HAVE USED TO COMPUTE DCF EQUITY COSTS. START WITH THE WATER UTILITIES SAMPLE. MR. REIKER CONTENDS YOU SHOULD HAVE INCLUDED CONNECTICUT WATER SERVICE AND MIDDLESEX WATER IN THE SAMPLE USED TO MAKE DCF ESTIMATES FOR THE WATER UTILITIES. WHAT IS YOUR RESPONSE?**

A. I did not include Middlesex Water and Connecticut Water Service in my 2002 sample because their rapid increases in stock prices coupled with low expected growth suggested they were merger candidates. Information for Middlesex Water has changed since last year. Middlesex Water now has an above-average dividend yield of 4% and analysts' forecasts reported by investor services indicate Middlesex Water is expected to have 7% growth. If I had included it in my sample, my average DCF equity cost would be higher than 10.8% because Middlesex Water has an estimated equity cost of 11%. Thus, the rapid growth in Middlesex Water stock prices I observed last year may well reflect the dividend yield and forecasted growth investors expect for it. Mr. Reiker also estimates equity costs for Middlesex Water with his multiple stage growth DCF model (Schedule JMR-6) and finds Middlesex Water has an above average cost of equity. I did not include Middlesex Water in my updated DCF equity cost estimate because it was not in the sample I presented last year.

Q. **WHAT ABOUT CONNECTICUT WATER SERVICE. DOES MR. REIKER EXPLAIN WHY CONNECTICUT WATER SERVICE HAS HAD A 50%**

INCREASE IN ITS STOCK PRICE WHILE STOCK PRICES FOR OTHER WATER UTILITIES INCREASED BY 12%?

A. No, he does not. Connecticut Water Service still appears to be a merger candidate and should not be included in a sample used to make DCF equity costs. At page 32, lines 18-22, Mr. Reiker agrees with me that if investors have bid up a stock price in anticipation of a merger, the DCF method could understate the cost of equity. If such a merger was anticipated for Connecticut Water Service, presumably, Mr. Reiker would not include it in his equity cost estimation sample. The data Mr. Rieker provided in support of Chart 3 at page 33 shows Connecticut Water Service had a price increase of 50% in 2001, the largest price increase of any water company other than American Water Works (a known merger candidate). That price increase compares to an average increase of 12% for the five other water utilities in Mr. Reiker's sample. His Chart 3 shows stock prices for Connecticut Water Service have subsequently moved in line with stock prices for other water utilities. With reasonably efficient markets, even for a thinly-traded stock such as Connecticut Water Service, one should expect information about potential mergers to continue to be embedded in its stock price unless merger rumors disappear. With such a super-inflated stock price, as Mr. Reiker observes, dividend yield and DCF equity cost estimates will be biased downwards. The behavior of Connecticut Water Service stock prices shown in Chart 3 is perfectly consistent with reasonably efficient markets in which investors expected a merger and thus supports my choice to leave it out of the water utilities sample adopted to make equity cost estimates with the DCF model.

Q. **TURN TO MR. REIKER'S COMENTS ABOUT THE SAMPLE YOU USED TO ESTIMATE DCF EQUITY COSTS FOR THE GAS UTILITIES. HE CONTENDS THAT CASCADE NATURAL GAS AND SOUTHWEST GAS**

SHOULD BE INCLUDED IN THE GAS UTILITIES SAMPLE. WHY DID YOU EXCLUDE THEM?

A. I have used the adjusted equity cost estimates for the gas utilities as another proxy for the cost of equity for those water utilities. All of the publicly-traded water utilities (with bond-ratings) that are in my sample of four water utilities and in Mr. Rigsby's sample of three water utilities have a bond rating of A or better. Cascade Natural Gas and SW Gas have bond rating of BBB/Baa and thus are more risky than the sample water utilities. Thus, it is inappropriate to include Cascade Natural Gas and SW Gas in the sample used to estimate equity costs for the lower risk water utilities.

Q. DO YOU HAVE ANY COMMENTS ABOUT MR. REIKER'S GAS UTILITIES SAMPLE?

A. Yes. It is puzzling why Mr. Reiker advocates including those two companies but not including South Jersey Industries. At this time, *C. A. Turner Utilities Reports* indicates South Jersey Industries has a split bond rating of Baa1/A and 80% of its revenues coming from gas operations. This company does meet the relevant criteria, yet has been ignored by Mr. Reiker. I did not include it because last year, when I prepared my direct testimony, *C. A. Turner Utility Reports* indicated that South Jersey Industries had 53% of its revenues from gas operations. I do not include South Jersey Industries in the sample used to make my updated DCF equity cost estimates because it was not in the sample I used to prepare direct testimony.

Q. WHAT IS SHOWN IN REBUTTAL TABLE 7?

A. Rebuttal Table 7 shows beta estimates for the samples of gas and water utilities at the time I prepared my direct testimony and today. To update the gas utilities sample beta I have included South Jersey Industries. There were no differences in average beta estimates when I prepared my direct testimony. However, to be conservative, I assumed the gas utilities required a 50 basis point risk premium when compared to water utilities. The average *Value Line* beta for the updated sample of gas utilities is now higher than it was last year. Below, I discuss potential downward bias in *Value Line* beta estimates for the thinly-traded water utilities. Even if that potential bias is ignored, Rebuttal Table 7 indicates the difference in the required returns for gas and water utilities is very close to the 50 basis points I adopted in my direct testimony and thus I do not revise that 50 basis points in my updated equity costs for the gas utilities.

Q. NOW TURN TO THE ISSUE OF DIVIDEND YIELDS. MR. REIKER ARGUES THAT SPOT PRICES SHOULD BE ADOPTED TO DETERMINE DIVIDEND YIELDS INSTEAD OF AVERAGE YIELDS. WHY DON'T YOU USE SPOT PRICES TO COMPUTE THE DIVIDEND YIELDS?

A. For at least three reasons. First, there are no estimates of "spot" growth rates to combine with the estimates of spot prices. *Value Line*, for example, updates its growth rate forecasts every three months. Other investor services report forecasts of growth rates made by analysts for the last 30 to 120 days. The constraint on the quality of the equity cost estimate comes from the quality of the growth rate estimates, not easily measured dividends and prices. Spot yields provide a false sense of accuracy and should not be used to estimate DCF equity costs. Second, prices for thinly-traded stocks, such as water utilities, are not as efficient as prices for larger stocks. I discuss this further in my discussion of bias in beta estimates. Third, it takes many weeks for analysts to prepare and ultimately present equity cost estimates. Allowing the analyst to choose the "spot" price also allows the analyst to bias his/her estimate of the dividend yield by choosing a price that is higher or lower than other prices he/she could have chosen during the period in which the testimony was prepared. This potential for gaming the equity cost estimate with the "spot" yield is avoided when average yields for a reasonably current period are adopted.

Q. MR. REIKER RAISES A NUMBER OF ISSUES RELATED TO THE GROWTH RATES YOU ADOPTED TO MAKE YOUR DCF ESTIMATES. AT PAGES 37-39 AND IN FIGURE 1, MR. REIKER ARGUES YOU MADE AN "ERROR" BY USING AN INDUSTRY AVERAGE GROWTH FORECAST FOR UTILITIES WHEN YOU DID NOT HAVE RELIABLE COMPANY-SPECIFIC GROWTH FORECASTS. DO YOU HAVE A RESPONSE?

A. Yes. His statement is equivalent to "the pot calling the kettle black", i.e., it is a correct method if he does it, but not a correct method when I do it. In Mr. Reiker's own analysis in Schedule JMR-6, his work paper (GrowthCalc, cell H 25) shows he used an industry average forecast (an average of forecasts of DPS growth rates for the water utilities for which he had forecasts) to estimate future dividend growth for Connecticut Water Service, Middlesex Water and SJW Corp when he prepared Schedule JMR-6. If the industry average forecast is the best available information, that industry average forecast is what investors would rely upon to price stocks. Mr. Reiker's testimony at pages 37-39 and Figure 1 should be ignored.

Q. AT PAGES 39-44, HE CONTENDS YOU RELIED EXCLUSIVELY ON ANALYSTS' FORECASTS OF EPS GROWTH TO PREPARED YOUR DCF EQUITY COST ESTIMATES. DID YOU?

A. No. Mr. Reiker says I place "exclusive reliance on analysts' forecasts of near-term earnings growth" (page 39, line 9) when I did not. In making all of my DCF equity cost estimates for water and gas utilities in both my direct testimony and rebuttal update of testimony, I relied upon forecasts of sustainable growth (forecasts Mr. Reiker calls "intrinsic growth") as well as analysts' forecasts of EPS growth to make my estimates. He has mischaracterized my testimony.

Q. **AT PAGE 40-41, HE DISCUSSES THE GORDON, GORDON AND GOULD PAPER AND A MORE RECENT SPEECH MADE BY PROFESSOR GORDON. IS YOUR TESTIMONY AT ODDS WITH GORDON'S ARTICLE AND SPEECH?**

A. No. Again, Mr. Reiker mischaracterizes my testimony. I correctly reported that Gordon, Gordon and Gould ("Choice Among Methods of Estimating Share Yield," *Journal of Portfolio Management (Spring 1989)*) ("GG&G") found that forecasts of EPS growth outperformed three measures of past growth. Such a finding clearly supports the use of EPS growth as one of the measures of growth investors would examine. I never said that GG&G argued for the <u>exclusive</u> use of analysts forecasts to implement the DCF model.

Also, if, as Mr. Reiker suggests should be done at page 41, GNP growth were used to make DCF equity cost estimates with the constant growth DCF model, Mr. Reiker's DCF equity cost estimate for the water utilities shown in Schedule JMR-7 would increase 150 basis points, from 8.5% to 10.0% if his GNP growth forecast from Schedule JMR-6 were used:

Equity cost = 3.47% + 6.5% = 10.0%

Q. **DO YOU HAVE ANY COMMENTS ABOUT HIS TESTIMONY AT PAGE 42 TO 44?**

A. Yes. I am not surprised that some writers have the view that analysts' forecasts of EPS growth have been too high after the recent stock market bubble burst and seriously damaged portfolios of many investors. It is always easy to look back now and find that the rosy future many believed was just over the hill was not realistic.

As to earlier studies, such as David Dreman's study, I did an analysis of *Value Line* ROE forecasts for gas distribution companies in 1999 and found that contrary to claims such as the one Mr. Reiker reports at page 42, line 4, in real terms (i.e., forecasts adjusted for the difference in expected and actual inflation) the *Value Line* ROE forecasts for gas distribution utilities were unbiased. My analysis showed overstatements in the ROE forecasts were the result of inaccurate forecasts of inflation. Earnings per share forecasts would vary directly with ROE forecasts. Putting one's head in the sand and assuming the past will continue into the future when the future may be much different, however, is not the answer. Investors look forward and they, too, may be making poor forecasts of inflation that are the same as the poor forecasts being relied upon by analysts. But if the analysts and the investors are making the same mistakes, the cost of capital is still revealed by looking at such analysts' EPS forecasts.

Mr. Reiker's anecdotal testimony reported on pages 42 through 44 still provides no basis to assume analysts' forecasts are not relied upon by investors when they price stocks. Had Mr. Reiker read Mr. Dreman's book, he would have seen the author's conclusion supports an inference that investors generally do rely on the analysts' forecasts. Dreman says:

"We have also seen that in spite of high error rates being recognized for decades, neither analysts nor investors who religiously depend on them have altered their methods in any way." (David Dremand, *Contrarian Investment Strategies: The Next Generation.* Simon & Schuster. New York page 115-116.)

If investors depend on the analysts' forecasts – whether the forecasts turn out to be excellent or poor forecasts -- they are relevant to a determination of DCF equity costs.

Q. AT PAGE 45, MR. REIKER PROVIDES TWO QUOTATIONS FROM YOUR TESTIMONY AND DEPOSITION IN UM 903, A 1998-1999 INVESTIGATION INTO AN APPROPRIATE METHOD TO DETERMINE

RECOVERY OF PURCHASED GAS COSTS IN OREGON. DO YOU HAVE ANY COMMENTS ABOUT THE QUOTATIONS HE CITES?

A. Yes, his quotations were very carefully selected to imply I used DPS forecasts to determine equity costs with the constant growth DCF model in a 1999 case, when that is not true. Mr. Reiker has the full testimony and knows that is not the case. He has taken one statement in a deposition out of context and thus misrepresents the analysis I presented in that case. The first cite is to page 9 of my deposition. I have attached the title page and pages 8 through 11 of that deposition at Tab C, labeled as Exhibit TMZ-3, to put the citation in context. Mr. John Thornton, now an employee of the Arizona Corporation Commission, was present and asking the questions at the deposition. He is providing rate design testimony in this case. My testimony (NWN/300/Zepp, dated December 17, 1998) was the subject of the deposition. It was rebuttal of Mr. Thornton's equity cost estimate presented in that case. Exhibit TMZ-3 shows that (1) the quote cited by Mr. Reiker was my second response to a question proposed by Mr. Thornton and it restated the question as Mr. Thornton asked it and (2) my first response referred Mr. Thornton back to my prefiled testimony.

Q. WHAT DID YOU SAY ABOUT THE USE OF DIVIDEND PER SHARE GROWTH IN THE PREFILED TESTIMONY TO WHICH YOU REFERRED?

A. I said the following:

Q. WHAT DO YOU CONCLUDE FROM YOUR EXAMINATION OF PAST AND FORECASTED EPS GROWTH?

A. Mr. Thornton's selective exclusion of EPS growth from consideration has biased downward his estimate of future DCF growth expected by investors for at least two reasons:

(1) EPS growth would be considered by investors in determination of future growth. Based on data in Mr. Thornton's work papers and past growth, that consideration would indicate expected growth of 6.5%, 7.8% and 8.6%. All three of these growth rates are above the range of DCF growth rates chosen by Mr. Thornton.

(2) The fact that past and forecasted DPS growth rates are lower than past and forecasted EPS growth rates indicates that investors would expect the LDCs [local gas distribution companies] to be financially stronger in the future. As a result, investors would expect the LDCs to be able to sustain **higher levels of dividend growth in the future than in the past and to achieve higher growth in the long term** than is forecasted for the [near term] period out to 2003. (Emphasis added.)

Oregon PUC, UM 903/AR 245/NW Natural/300, pages 19-20.

Q. IS THE UM 903 TESTIMONY QUOTED BY MR. REIKER CONSISTENT WITH YOUR TESTIMONY IN THIS CASE?

A. Yes, it is. Just as I said in Oregon Docket UM 903, if EPS growth is expected to be more rapid than DPS growth, investors will expect future sustainable growth to be higher than near-term DPS growth. Future DPS growth and historic DPS growth are undoubtedly the worst measures of long-term sustainable growth in such a situation. Those measures of growth would not be relied upon by rational investors making equity cost estimates with the constant growth DCF model. Giving any weight to such DPS growth estimates will bias downward equity cost estimates.

Q. DO YOU HAVE ANY COMMENTS ABOUT MR. REIKER'S CITE AT LINES 11-13 OF PAGE 45?

A. It, too, is taken out of context. The questions and answers starting before and ending after the cite are shown below:

Q. WOULD INVESTORS EXAMINE INFORMATION OTHER THAN BR + VS GROWTH TO DETERMINE THE COST OF EQUITY FACING GAS LDCS?

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A. Yes. Investors would examine past and forecasted growth in earnings per share ("EPS"), dividends per share ("DPS") and other trends that provide indications about what future growth would be.

Q. MR. THORNTON BASED HIS GROWTH RATE RANGE OF 3.0% TO 5.0% IN PART ON PAST AND FORECASTED DPS GROWTH. IF INVESTORS WERE TO LOOK AT ONLY EPS OR DPS GROWTH, WHICH ONE WOULD THEY EXAMINE?

A. Available evidence indicates they would look at EPS growth. Investors are willing to pay for compilations of investor analysts' forecasts of EPS growth, such as Standard & Poor's Earnings Guide.

UM 903/ AR245/ NW Natural/ 300, pages 17-18.

This testimony, together with the testimony at UM 903/ AR245/ NW Natural/ 300, page 20 reported above, are totally consistent with my testimony in this case. That testimony is that when forecasts of DPS growth (or past DPS growth) are smaller than expected EPS growth (past EPS growth), reliance on DPS growth as the growth rate in the constant growth DCF model will bias downward the equity cost estimates.

Q. TURN TO YOUR RESPONSE TO MR. REIKER'S CRITICISMS OF YOUR RISK PREMIUM ESTIMATES. AT PAGE 46-47, MR. REIKER ARGUES BLUE CHIP CONSENSUS FORECASTS OF INTEREST RATES SHOULD NOT BE RELIED UPON TO MAKE RISK PREMIUM EQUITY COST ESTIMATES. DO YOU HAVE A RESPONSE?

A. Yes. Mr. Reiker offers Chart 4 to support his recommendation. The data underlying the chart show that in the three years 1999 to 2001, the projected Blue Chip interest rates were lower than actual rates and in the two years 2002 to 2003, projected rates were higher than has occurred. On average the Blue Chip forecasts have been 14 basis points below the rates that have actually occurred.

Interest rates that should be relied upon to determine Arizona Water's cost of equity should be interest rates expected during the period in which new tariffs will be in effect. Relying on "actual" market interest rates in 2003 does not solve the problem of uncertainty about future rates. Actual current Baa rates as well as forecasts of Baa rates, depend upon investors' perceptions of what will happen in the future. As a result, the quotation Mr. Reiker offers at page 47 from Jacob and Pettit cannot be a criticism of my choice to use Blue Chip forecasts of the Baa rates. Mr. Reiker's own Chart 4 shows that to the extent there has been any difference between actual rates and the Blue Chip forecasts of rates, on average, bond rates turned out to be higher than was estimated with the Blue Chip consensus forecasts.

In Mr. Reiker's CAPM testimony, he adopted actual rates instead of forecasts of those rates to make CAPM estimates. But those actual rates are a weighted average of short-term rates in 2003 and rates in the future; thus, those current rates reflect interest rates that exist before the period in which Arizona Water's new tariffs will be established. Based on actual market data on July 30, 2003, the benchmark 10 year Treasury rate (currently 4.38%) is 37 basis points below the forward 10 year Treasury rate expected by investors next year (4.75%). The forward rate is almost a full percentage point (95 basis points) above the 10-year Treasury rate Mr. Reiker relied upon to prepare his equity cost estimates 3.80% (Reiker Direct, footnote 12). Thus, for similar reasons, forecasts of Baa rates are preferred to current Baa rates because they provide estimates of the costs of bonds expected when the new tariffs for Arizona Water will be in place. To the extent that current short-term interest rates are lower than interest rates expected in the future, the use of current Baa rates will understate the relevant cost of equity. Blue Chip forecasts reflect the pure forecast of the rates after the 2003 short-term rates are history. With interest rates at forty year lows, the chance future rates will be higher than today is much better than the chance they will be lower. As a result, the forecasted rates should be adopted.

Q. MR. REIKER SAYS THE CAPM SHOULD BE USED INSTEAD OF YOUR RISK PREMIUM APPROACHES. DO YOU HAVE ANY RESPONSE TO THAT TESTIMONY?

A. Yes. My response is in Section IV of my testimony.

Q. REFERRING TO PAGE 48-49 OF MR. REIKER'S TESTIMONY, DOES THE FACT THAT CORPORATE BONDS MAY HAVE CHANGING DEFAULT RISK PREMIUMS MEAN ONLY TREASURY SECURITIES SHOULD BE USED TO COMPUTE RISK PREMIUM ANALYSES?

A. Of course not. Such a statement implies equity costs are more closely tied to costs of Treasury securities than to the utilities' own costs of debt. It is more logical to expect equity costs to reflect changes in corporate debt costs than to assume those equity costs move in lockstep with interest rates the government can obtain in the market. This was especially true during the last several years when there was a flight to quality and investors bid up long-term Treasury security prices (and bid down yields) in anticipation that the government would issue fewer Treasury securities. Now that a new huge deficit appears to be emerging, the latter concern may go away and the spread between equity costs and Treasuries rates will change again. Of the two choices, corporate bonds and Treasury securities, logically the corporate bonds are expected to have the more stable risk premium.

Q. REFERRING TO PAGE 49, ARE THERE GREATER PROBLEMS WITH YOUR RISK PREMIUM APPROACHES THAN THE CAPM IF RISK

PREMIUMS CHANGE OVER TIME?

A. No. I discuss this issue in section IV. There are greater problems with the CAPM as I explain in Section IV.

Q. SHOULD ANY WEIGHT BE GIVEN TO STAFF'S CONCERNS WITH THE RISK PREMIUM ANALYSIS YOU PRESENTED IN TABLE 22?

A. No. Staff chose to write this testimony instead of asking for my work papers. In response to the specific three points they raise: (1) The water utilities in the CPUC sample are the companies in Mr. Reiker's sample plus American Water Works. (2) The utilities in the CPUC sample are seven of the companies in the list of utilities followed by C. A. Turner Utility Reports. (3) On average, for the period 1991-2000, the seven water utilities earned ROEs that were 48 basis points lower than authorized. Rebuttal Table 17 is the work paper I would have sent to Staff if they had requested it. My estimate of 40 basis points in Table 22 was conservative.

Q. DO YOU HAVE ANY COMMENT ABOUT MR. REIKER'S REBUTTAL OF THE RISK PREMIUM ANALYSIS YOU PRESENTED IN TABLE 23?

A. At lines 2-11 of page 38 of my direct testimony, I have already explained why it is appropriate to consider authorized ROEs as measures of the cost of equity and pointed out the FERC has made such a determination in the past. I do not repeat that testimony again.

Q. DO YOU HAVE ANY COMMENTS ABOUT MR. REIKER'S CRITIQUE OF THE RISK PREMIUM ANALYSIS YOU PRESENTED IN TABLE 24?

A. Yes. Based on the data underlying Chart 6, the current gas utility beta is the same as the average beta over the period shown in Chart 6. I do not agree that beta risk is the only systematic risk that is relevant to investors, but if one limits consideration of risk to Mr. Reiker's measure of risk, Mr. Reiker's Chart 6 supports the use of the risk premium analysis I present in Table 24 and my update of that analysis in Rebuttal Table 15. Based on Mr. Reiker's analysis, beta risk today is the same as it has been, on average, during the period the average risk premium was estimated. Contrary to his statement at page 52, line 10, past risk and returns are relevant if the current beta is relevant.

Q. **DO YOU HAVE ANY COMMENT ABOUT HIS TESTIMONY AT PAGE 52-53 AND HIS CHART 7 AND CHART 8?**

A. Yes. Mr. Reiker says I said things I did not say. I compared authorized ROEs for Arizona utilities during the period 1997 to 2001 (shown in my Table 10) to interest rates that prevailed during the same period (my Table 9). This comparison showed that in all but the most recent case, the authorized ROEs for Arizona utilities were in a range of 10.5% to 12.0% when the range of interest rates were in a range of 7.32% to 8.37%. As shown in Rebuttal Table 1, such authorized ROEs in Arizona are in line with the ROEs earned and authorized for utilities in Mr. Reiker's sample of publicly traded water utilities. Mr. Reiker argues that interest rates going back to 1967 are of interest when they have nothing to do with the comparison I presented. In the period prior to 1997, equity costs would have been higher when interest rates were higher.

Q. **AT THE BOTTOM OF PAGE 53, MR. RIKER CLAIMS YOUR TESTIMONY SUPPORTS AN EQUITY COST OF 9%. HOW DID HE DERIVE THAT FIGURE?**

A. He derived a 9% equity return by using one year of data and ignoring the other 10 years of data presented in Table 8 of my direct testimony. The purpose of Table 8 was to provide internally consistent estimates of the differences in costs of equity for large and small water utilities. To make those estimates I relied upon methods the California PUC Staff used in past cases.

In order for Mr. Reiker to fabricate the 9% ROE estimate he presents at the bottom of page 53, he had to carefully select data for one of the 11 years and ignore the other data in the Table 8. See Rebuttal Table 18. If the data in Table 8 are used to compute another risk premium estimate -- as Mr. Reiker suggests -- the appropriate thing to do is use data for all of the years, not just one year. I have done that in Rebuttal Table 18 and compute the average risk premium above Baa bond rates for the larger water utilities to be 2.82%. Combining that estimate with the current forecasted range of Baa rates indicates a cost of equity for the larger water utilities of 9.9% to 10.5%. And, adding in the 100 to 150 basis point risk premium required uniquely by Arizona Water, the implied equity cost for Arizona Water is 10.9% to 12.0%, substantially higher than the 9% estimate he says my testimony would support.

III. <u>SIZE AND OTHER RISKS REQUIRE THAT ARIZONA WATER BE AUTHORIZED AN EQUITY</u>

A. <u>Risk premium of 100 to 150 basis points.</u>

Q. AT PAGE 55-56, MR. REIKER DISCUSSES ARIZONA WATER'S RECENT BOND PLACEMENT. CAN ARIZONA WATER EXPECT TO ISSUES BONDS AT A COST THAT AN A-RATED WATER UTILITY OR AA-RATED WATER UTILITY COULD EXPECT?

A. Absolutely not. The three water utilities with bond ratings that Mr. Rigsby and I adopt to estimate equity costs currently have S&P bond ratings of either AA- or A+. After a 9 month search for someone to buy the issue, when Arizona Water issued its series K bonds, the Company's cost of debt was 37 basis points higher than the cost of A-rated bonds and 49 basis points above the cost of AA-rated bonds at the time the rate on the series K bonds was set.

Q. WHAT IS THE IMPLICATION OF THIS COST OF DEBT WHEN THE COMMISSION DETERMINES ARIZONA WATER'S AUTHORIZED EQUITY RETURN?

A. The implication is that Arizona Water requires a higher equity return than the cost of equity estimated for the A-rated and AA-rated water utilities. Basic finance principles tell us that a utility's cost of equity is higher than its cost of debt. If all water utilities have equity costs that are the same margin above their respective costs of debt, evidence from the series K issue for Arizona Water indicates the Company requires a risk premium that is at least 37 to 49 basis points above the benchmark costs of equity estimated for the water utilities sample. (At the time the series K rate of 8.04% was set, the cost of A-rated utility bonds was 7.67% and the estimated cost of AA utility bonds was 7.55%). Other evidence presented in my direct and this rebuttal show that such a range of equity cost adders is a conservative measure of the premium Arizona Water requires. As discussed in my direct testimony and further below, the full premium falls in the range of the 100 to 150 basis point risk premium I recommend for the Company.

Q. DO YOU HAVE ANY COMMENTS ABOUT MR. REIKER OR MR. RIGSBY'S RESPONSES TO YOUR STATEMENT THAT HISTORICAL TEST YEARS AND OTHER PROCEDURES IN ARIZONA INCREASE ARIZONA WATER'S RISK?

A. Yes. Neither Mr. Reiker (pp. 56-57) nor Mr. Rigsby (pp. 59-62) explain why the risks related to historical test years do not increase one or more systematic risks. Mr. Reiker mentions uncertain consumption; surely, that would increase beta risk because consumption will vary with economic activity. A lack of streamlined procedures, automatic adjustment mechanisms and limited post-test year adjustments would increase the distress systematic risk identified by Fama and French.

Q. MR. REIKER (p. 57) AND MR. RIGSBY (p. 62) CLAIM THAT ARIZONA WATER DOES NOT FACE ADDED RISK BECAUSE OF CHANGES IN EPA REQUIREMENTS YOU ADDRESSED IN YOUR DIRECT TESTIMONY. DO YOU AGREE?

A. No. The new maximum contaminant level established by the Environmental Protection Agency for arsenic in public drinking water will require substantial new investments by Arizona Water as well as much larger annual expenses. Mr. Kennedy discusses these substantial costs in his rebuttal testimony. As I explained in my direct testimony (page 12-13 and15-18), there is no doubt about how such new requirements impact risk. An investor would much prefer to own the lower risk utility that does not have to make such investments or attempt to recover such annual increases in operating costs. This is yet another instance where Mr. Reiker makes cavalier claims based on the original Sharpe-Lintner model. Without any empirical support, he dismisses my testimony by saying such risks are not priced by investors. Common sense tells us that beta risk would be expected to increase as expenses become more uncertain and covariance with the market undoubtedly increases to some extent. Alternatively, added investments and expenses required by the revised EPA requirements may increase another systematic risk, distress risk. Mr. Reiker is apparently unwilling to acknowledge there are other systematic risks such as distress risk. Mr. Rigsby dismisses my statement because there is a pending decision that will establish some sort arsenic recovery mechanism. Such a recovery mechanism – even if ideal – would not eliminate the Company's need to raise capital to pay for the added investments. It is my understanding, however, that the proposed cost recovery mechanism, if approved, would not allow full cost recovery, a situation far from the ideal. And, as a company – particularly a small company like Arizona Water with relatively limited access to financial markets -- has to make above average investments, investors require higher returns. I presented a study I made that found electric utilities with above average investment requirements were more risky than those with below-average investment requirements. (Zepp Direct, page 13) Neither Mr. Reiker nor Mr. Rigsby found fault with that study and neither of them show why it would not be applicable to water utilities that are required to make larger than average investments to meet EPA requirements.

Q. **ARE THERE OTHER CONCERNS RELATED TO THE NEED TO MAKE SUBSTANTIAL NEW INVESTMETNS TO MEET EPA REQUIREMENTS?**

A. Yes. Arizona Water Company must increase its equity position to enable the Company to convince lenders, such as insurance companies, that the Company has sufficient financial strength to borrow more money and pay interest and principle on new bonds. It is unavoidable that new debt will be needed to fund the additional investment in plant to deal with the new arsenic standard. Arguments such as Mr. Reiker and Mr. Rigsby present would penalize the Company for attempting to improve its financial strength. The Company should not be penalized for proper planning for future needs and requirements to provide quality service to its customers.

Q. **DO YOU HAVE A RESPONSE TO MR. REIKER AND MR. RIGSBY REGARDING THE CALIFORNIA PUC FINDING THAT PARK WATER COMPANY REQUIRED A RISK PREMIUM BECAUSE OF ITS SMALL SIZE AND OTHER FACTORS?**

A. Yes. Mr. Reiker (p. 63) finds "several problems" with it. He asserts that the California CPUC, considered what Mr. Reiker classifies as numerous "unsystematic risks," in reaching a decision and thus the Arizona Corporation Commission should not rely on the CPUC finding. Instead of evaluating how the evidence in the Park case might actually indicate Park Water faced an increase in one or more systematic risks (beta, size or distress) he dismisses the CPUC decision because he concluded – without any study – that beta risk for Park Water was not higher than benchmark water utilities. Mr. Reiker's conclusion, not the CPUC finding, should be ignored. By way of footnote, in the Proposed Decision in Park Water Company's current case (A.02-03-046), the Administrative Law Judge proposed the 30 basis point risk premium should continue.

Mr. Rigsby (pp. 51-54 and 56-59) suggests that the 30 basis point premium authorized for Park Water must have been due to exposure to catastrophic events (pp.56-59) because -- in his opinion -- such a risk premium is not justified by Park being small (about the size of Arizona Water). I explain below that the evidence he relies upon to reject size as a risk factor does not provide that support and thus his opinion should be disregarded.

Q. AT PAGES 26 to 30 AND AGAIN AT PAGE 68, MR. REIKER ARGUES ARIZONA WATER IS LESS RISKY BECAUSE IT HAS LESS FINANCIAL RISK THAN HIS SAMPLE OF WATER UTILITIES. WHAT IS YOUR RESPONSE?

A. I have three responses.

First, it ignores known facts. He ignores the fact that Arizona Water, even with a book equity ratio that is less leveraged than the sample water utilities, is unable to obtain debt at a cost as low as those utilities. At the time the cost of the Company's last bond issue was set, it had a cost of debt that was 37 basis points above the cost of A-rated bonds and 49 basis pints above the cost of AA-rated bonds. Something else must be going on. The most obvious answer is that

Arizona Water has additional business risk that more than offsets its lower financial risk. The now classic study by Scott and Martin ("Industry Influence on Financial Structure," *Financial Management*, Spring 1975, pp. 67-71) found statistically significant results for unregulated firms that show ". . . smaller equity ratios (higher leverage use) are generally associated with larger companies" (page 70). It is reasonable to presume those unregulated firms attempted to have the lowest cost capital structures. The results of their study indicates smaller firms attempting to minimize costs will have higher equity ratios to offset higher business risks. In the case of Arizona Water, those higher business risks include its small size, lack of financing flexibility, limited access to bond markets, and the need to make significantly larger investments to address arsenic problems than the water utilities in the benchmark sample. In Docket W-1445A-00-0962, I presented a discussion of the Scott and Martin study in support of smaller companies requiring higher equity ratios. Mr. Reiker responded by offering a study by Titman and Wessels ("The Determinants of Capital Structure Choice," *Journal of Finance*, Vol. 43, March 1988). But the Titman and Wessels study cautioned readers that their study was limited to the manufacturing sector of the economy (page 9) whereas the Scott and Martin study considered twelve different industries (page 67). But notwithstanding the "duel" of alternative studies, the plain fact remains that even when Arizona Water has a higher book equity ratio than the sample companies, it cannot issue debt at a cost as low as those companies can issue debt.

Second, the fatal flaw in his analysis comes in two parts. First, Mr. Reiker has used the wrong measure of equity to implement formula (6) he presents at page 27. In response to a data request, Mr. Reiker provided documents showing the definition of "equity capital" required for his analysis was the <u>market</u> value of equity, not <u>book</u> equity that he used in his analysis. Rebuttal Table 19 shows the

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dramatic difference that occurs when the correct measure of equity capital is adopted. Instead of the unlevered beta being .36, it is .46. But of greater importance to the argument Mr. Reiker makes, the relevant equity ratio for the sample companies becomes 68%, not 50%, no matter what measure of beta is used. The second part of the fatal flaw is that Mr. Reiker cannot know what Arizona Water's "market value" is because the Company does not have one. Arizona Water only has a book equity ratio of .65 to compare to the market equity ratio of .68 for the sample companies. Without speculating about what Arizona Water's unknown "market price" would be, Mr. Reiker cannot make the calculation of the "relevered" beta he pretends can be computed. (If, for example, the Company's market-to-book ratio were equal to 1.0, Arizona Water would be more, not less leveraged than Mr. Reiker's water sample.) Mr. Reiker's analysis has no foundation and thus should be ignored.

Third, even if all of the other faults in his analysis at pages 26-30 were ignored, Mr. Reiker's analysis is flawed because he has assumed his answer when he assumes that Arizona Water has the same business risk (i.e., unlevered beta) as other water utilities. He has no evidence to make such a result-driven assumption. One cannot compute a "relevered" beta for Arizona Water from an unlevered beta for utilities with lower business risk (and thus a smaller unlevered beta). Mr. Reiker does not and cannot know the magnitude of Arizona Water's unlevered beta from the data he has presented.

Q. DOES ARIZONA WATER REQUIRE AN EQUITY RISK PREMIUM BECAUSE IT IS SMALLER THAN THE UTILITIES IN THE WATER UTILITIES SAMPLE ADOPTED TO MAKE BENCHMARK EQUITY COSTS?

A. Yes, it does. There is general agreement that there is a small firm effect and that small firms (in general) require a higher return than larger firms. Every year for the past several years, Ibbotson Associates have published studies that show smaller firms have bigger betas than larger firms and even when the bigger betas are recognized, small firms still require an additional risk premium. Fama and French also have conducted studies in which they found there are three -- not just one -- systematic risks. Those systematic risks relate to the market (the traditional CAPM beta), size (smaller is more risky) and distress (more distress requires higher returns). The question is not whether there is a small firm effect but whether there is a small firm effect for utilities as well as other stocks.

Q. YOU SAY SOME SCHOLARS HAVE ESTIMATED MORE THAN ONE SYSTEMATIC RISK. HOW DO YOU DISTINGUISH BETWEEN SYSTEMATIC AND UNSYSTEMATIC RISKS?

A. The original Sharpe-Lintner CAPM splits risk into two categories: systematic risk (beta risk) and unsystematic risk. Assuming markets are efficient and that investors price stocks to reflect expected returns, realization of the unsystematic risks in the future would be random and thus not priced by investors. Unsystematic risks are the result of unexpected events and would not be priced by investors. Investors may well take into account an expectation that old water mains will have to be replaced by water utilities. In the more complete asset pricing model, stock prices for water utilities with larger future investment requirements would be lower (relative to book value) than stock prices for water utilities with mains that have already been replaced. This market response would most logically be reflected in what Fama and French have called "distress" systematic risk. It might also impact beta risk. In this multi-risk model, there are still unsystematic risks. But those unsystematic risks occur as unexpected damage to mains occurs or the mains wear out faster or slower than expected. Risk related to expected expenditures to replace mains (compared to other water utilities) would already be priced by investors.

Mr. Reiker and I agree that unsystematic risks would not be priced by investors. But the true unsystematic risk (in the example) relates to unexpected changes in returns caused by the need to replace mains. The risk associated with the expected cost of replacing mains would already be priced by investors. With Mr. Reiker's simplistic view of the world, all of the risk – expected and unexpected -- would be classified as "unsystematic risk" and ignored unless it caused a difference in covariance with market returns.

The original CAPM can be expressed as a "Security Market Line". Professor Sharpe, one of the authors of that original CAPM, states that "other factors may matter" to investors, other than beta risk and return. In such a case Professor Sharpe says those other factors require consideration of a "security market plane" instead of the simple security market line. Sharpe, *Investments,* Third Edition, 1985, page 176-179. Specifically, Sharpe says:

> In an efficient market, all securities will plot on a *Security Market Hyperplane,* the axes of which plot contributions to all the attributes of efficient portfolios that matter (on average) to investors.

If, on average, an attribute is *liked* by investors, securities that contribute more to that attribute will, other things equal, offer *lower* expected returns. (emphasis in original) Sharpe, page 178.

As I use the term "systematic risk" I include all of those attributes (factors) that studies have found matter to investors. As I explained in my direct testimony, Ibbotson Associates conclude those systematic risks are risks related to the market

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and risk of company size. Fama and French have concluded the risks priced by investors are related to the market, distress and company size.

Q. MR. REIKER SPECIFICALLY SAYS THAT FIRM SIZE IS NOT A FACTOR THAT INVESTORS PRICE WHEN THEY BUY UTILITY STOCKS, THAT SIZE IS AN "UNSYSTEMATIC RISK" AND THUS SHOULD BE IGNORED. DO YOU HAVE ANY RESPONSE TO HIS TESTIMONY?

A. Yes. Mr. Reiker addresses this issue at pages 59 to 68 of his testimony. At page 59, he pats himself on the back because in two cases the Commission accepted his contention that the small firm effect does not exist for utilities. At page 60, he agrees that several studies have investigated the "firm size phenomenon". He specifically mentions Ibbotson Associates who have determined there is a small firm effect for common stocks in general, but notes the Ibbotson Associates study was not specific to the public utility industry. At page 60-61 he discusses the Wong study, the evidence Staff relies on to claim that though the small firm effect applies to stocks in general it does not apply to Arizona Water.

Q. DOES MR. RIGSBY ALSO RELY ON THE WONG STUDY ?

A. Yes, at page 48 he states that the Wong article provides a compelling argument as to why the size effect found by Ibbotson Associates for stocks in general does not apply to utilities.

Q. DO YOU HAVE NEW EVIDENCE THAT THE WONG ARTICLE SHOULD BE DISREGARDED?

A. Yes. Given the importance of this issue to the determination of a fair rate of return, I prepared an article and submitted it to *The Quarterly Review of Economics and Finance,* the successor to the journal that published Ms. Wong's article. My article, which is titled "Utility stocks and the size effect - revisited," *The Quarterly*

Review of Economics and Finance, 43 (2003) pages 578-582, went through the normal review and approval process of a scholarly journal. The journal received it January 7, 2002, reviewed and tentatively approved it in early 2002, sent it back to me for some editorial corrections, accepted it August 29, 2002 and will publish it this fall. I have attached at Tab C a pre-publication copy (an offprint) of that article sent to me by the publisher as Exhibit -TMZ-4.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS IN THAT ARTICLE.

A. The primary conclusions are (1) Ms. Wong did not question the small firm effect exists for industrial stocks but, contrary to the quotation Mr. Reiker relies on, her results do not rule out such an effect for utilities. (2) Alternative beta estimation techniques are expected to show small, thinly-traded utilities are more risky than larger ones. The methods Wong used to estimate betas would not capture such a result. (3) New information not available to Wong indicates there is a small firm effect in the utility sector.

Q. IS YOUR ARTICLE IMPORTANT FOR THIS PROCEEDING?

A. Yes. My article has been subject to independent review by scholars who realized the importance of it and accepted it for publication. My article shows the Wong article cannot be relied upon to claim there is no small firm effect for utilities.

Q. BASED ON YOUR STUDY, IS THE QUOTE PRESENTED BY MR. REIKER AT PAGE 61, LINES 8-16, SUPPORTED BY THE ANALYSIS WONG PRESENTED IN HER PAPER?

A. No, it is not. I address that quote in my paper. The second sentence in that quotation from Wong's article is factually incorrect. Actually, Wong did find utility betas varied inversely with size in one of two periods. Her Table 2 shows that result. Mr. Reiker just reported the quotation but did not bother to review the evidence Wong presented in Table 2. In my article, I explain why betas estimated for the second period, at least betas for small capitalized, thinly-traded utilities, are expected to be biased downward with the type of data Wong used to make beta estimates. Also, I explain that Wong's verbal justification for expecting no small firm effect for utilities when there is a small firm effect for other companies (the part of the quotation emphasized by Mr. Reiker) is inconsistent with regulatory procedures. Wong referenced two studies and suggested that the small firm effect may be explained by investors having more information for large companies than for small companies. She then incorrectly presumed that a differential in information does not apply to utilities. Wong was apparently unfamiliar with the fact that more information will be generated for large utilities than small utilities in rate cases and that in some jurisdictions large firms are required to file more information. It was a lack of a differential in information that led Wong to presume risks for different utilities would not depend on size (Exhibit TMZ-4). Knowledgeable investors would know there is a difference in information available for large and small utilities.

Q. DOES THE WONG ARTICLE SUPPORT A CONCLUSION THAT THERE IS NO SMALL FIRM EFFECT FOR UTILTIES?

A. No, it does not.

Q. MR. REIKER AND MR. RIGSBY DISCUSS THE SO-CALLED "JANUARY EFFECT". DO YOU HAVE A RESPONSE TO THEIR TESTIMONY?

A. Yes. They both suggest there may be no "January Effect" for utilities. Even if that is the case, it does not rule out the small firm effect. There are at least two independent justifications of the small firm effect that apply equally to small utilities and other small companies. One is the differences in information available to investors (see my paper, Exhibit TMZ-4) that refers to papers by Barry and Brown (1984) and Brauer (1986)). There is indeed less information generally available to investors of small utilities than larger ones and thus that justification of the small firm effect does not depend on there being or not being a January Effect for utilities.

Second, small firms are expected to have larger betas. Ibbotson Associates (2003) and Roll (1980) suggested the small firm effect may be in part explained by negatively biased beta estimates for the smaller thinly-traced stocks that is expected to occur when the time interval used to estimate betas is a month or less. I found that to be the case when I estimated betas for Dominguez Water and also find that to be the case in my article (Table 1, Exhibit TMZ-4). With such understatements of beta risk, there is a residual risk of relevance to investors that is the small firm effect. Such a potential beta estimation problem clearly exists for utilities as well as other small companies.

And, as to the discussion presented by Mr. Rieker, he offers only speculation and no quantitative study that supports the lack of a January Effect for small utilities. Investors could sell small utility stocks before the end of the year and buy them back in January, just like any small stock. Mr. Reiker suggests that the January Effect "would be larger for small firms because stocks of small firms are more volatile" (Reiker, page 62, line 4). If that is the reason for the small firm effect, it supports a small firm effect for the smaller water utilities (as compared to larger water utilities) if those small utilities have more volatile returns than the larger ones. Mr. Reiker gets confused and implies the small firm effect of relevance is based on a comparison of utilities to companies in other types of industries. (Reiker, page 62, line 8-9) That is not the issue. The small firm effect that should be recognized is the adder to the benchmark equity return for the larger water utilities. But whether the January Effect does or does not exist, it is only one of several explanations of the small firm effect.

Q. **IN RESPONSE TO YOUR STUDIES THAT SHOW SMALL WATER UTILITIES HAVE A HIGHER EQUITY COST THAN LARGER ONES, AT PAGES 44-47, MR. RIGSBY PRESENTS HIS INTERPRETATION OF A CHAN & CHEN ARTICLE, CLAIMS THE SMALL FIRM EFFECT IS DUE TO "MARGINAL FIRMS" AND THEN PROCEEDS TO COMPARE ARIZONA WATER TO SUCH MARGINAL FIRMS. DID YOU RELY ON THE CHAN & CHEN ARTICLE IN YOUR TESTIMONY?**

A. No.

Q. **DO YOU HAVE ANY COMMENTS ABOUT MR. RIGSBY'S ATTEMPT TO APPLY THAT ARTICLE TO ARIZONA WATER?**

A. Yes. I presented an analysis of water utilities in Table 8 of my direct testimony that compared the risk of two small water utilities to the risk of two larger water utilities. I found the smaller water utilities required an equity return that was 99 basis points higher. Neither of the two small utilities were "marginal firms" as Mr. Rigsby defines the term but those small water companies still had a higher cost of equity. Mr. Rigsby has made no showing that small water utilities must be "marginal firms" to be more risky and thus his attempt to compare Arizona Water to Chan & Chen's "marginal firms" does not address the issue of small water companies being more risky than large, publicly-traded ones.

Q. **MR. REIKER AND MR. RIGSBY CORRECTLY POINT OUT THAT THE CPUC STUDY YOU PRESENTED IN YOUR DIRECT TESTIMONY IS FOR UTILTIES THAT ARE SMALLER THAN ARIZONA WATER. EXPLAIN WHY YOU INCLUDED A DISCUSSION OF THAT STUDY.**

A. I presented it because it shows small water utilities have higher equity costs than the water utilities that Mr. Reiker, Mr. Rigsby and I use to determine benchmark equity costs. I did not propose that Arizona Water be authorized a risk premium as large as the risk premium required by water utilities the size of Class C and Class D water utilities in California. I presented the CPUC study to show that as water utilities are smaller, they require higher and higher ROEs than the larger water utilities.

Q. MR. REIKER ALSO CLAIMS THAT THE CPUC STAFF "COMPLETELY IGNORED FINANCE PRINCIPLES" WHEN IT ESTIMATED PROXY BETA ESTIMATES FOR THE SMALL PRIVATELY HELD WATER UTILITIES. DO YOU HAVE A RESPONSE?

A. Yes, the firms being examined were privately held and proxy estimates of betas were made. Mr. Reiker has provided no showing that the method used by the CPUC Staff to make proxy estimates of betas was not the best available one. Indeed, the fact that another public utility commission has taken a position contrary to Mr. Reiker indicates that Mr. Reiker's position is questionable. But more fundamentally, Mr. Reiker ignores the work of scholars such as Sharpe, who recognize there may be factors other than beta risk that are systematic risks of importance to investors. All risks other than beta risk are not automatically "unsystematic risk". Unsystematic risk is risk related to unexpected events. If a factor such as company size is priced by investors, it is <u>not</u> an unsystematic risk. Mr. Reiker apparently is unwilling to acknowledge that there are potential systematic risks related to company size and to distress that may not fall neatly into whatever he means by "corporate finance principles".

Q. AT PAGE 64 TO 68 AND IN EXHIBIT JMR-1, MR. REIKER PRESENTS A CRITICISM OF YOUR ANALYSIS IN TABLE 8. DO YOU HAVE A RESPONSE?

A. Yes. I respond to each of his criticisms in turn. First, he claims that I did not perform the appropriate statistical test and that if I had performed a "standard statistical test" it is plausible that the average difference between the costs of equity to larger and smaller water utilities is zero.

I conducted the correct statistical test. It is called a "Paired Difference Test." I have attached at Tab C, and labeled as Exhibit TMZ-5, a section from Professsor William Mendenhall's book *Introduction to Statistics* that explains why the test I performed is correct and the one that ACC Staff presented should not be used. Professor Mendenhall provides an example that is analogous to the analysis in my Table 8. Professor Mendenhall shows that if the "standard statistical test" (the one proposed by ACC Staff) were performed in a situation where the analyst is interested in whether there are significant differences in wear for two different types of tires (analogous to small and large water utilities equity costs) when those tires are mounted on five different cars driven by five different drivers (analogous to annual estimates of equity costs), the relatively large variability in the data would suggest there is no difference in wear on the tires (analogous to large difference in equity costs during an 11 year period) when a correct test would show there is a difference.

In Professor Mendenhall's example, there would be large variability in measured tire wear because the different drivers have different driving habits (analogous to difference in credit conditions in different years). Mendenhall goes on to point out that the statistical procedure proposed by ACC Staff requires the two samples be *independent* and random when tire wear (and equity costs at different points in time) is not. The pair of measurements of tire wear for a particular automobile (analogous to the pair of equity costs in a particular year) are definitely related. He points out that tire wear (equity cost estimates) are largely determined by driver habits (financial conditions in various years) and thus

Mendenhall concludes the paired difference test I use is appropriate and the test proposed by Mr. Reiker will substantially overstate uncertainty with the results.

Mr. Reiker's proposed test is wrong and should be ignored. I also note the editors and the referees of *The Quarterly Review of Economics and Finance* found no fault with the test I performed and accepted my Table 8 as Table 2 of my soon to be published article.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS ABOUT THE RESULTS YOU REPORT IN TABLE 8?

A. Yes. As a check on the observation that the various pairs of observations are not independent, one can test if the correlation between the two variables is significantly different than zero. It is. An F-test on whether the correlation between the observations is significantly different than zero produces a test statistic of 58.72. The F-statistic for the lowest level of significance (1%) in the table I examined was but 10.56. The obvious point – that equity costs at different points in time are dependent – is confirmed by the F-test. Clearly the pair-difference test I performed is the appropriate test and not the general test adopted by Mr. Reiker.

Q. DO YOU HAVE A RESPONSE TO HIS SECOND CRITICISM?

A. Mr. Reiker claims the only way I could find results to be statistically significant is to adopt an unusually low significance level. I do not agree I adopted an "unusually low," significance level. I don't know what that means. A standard t-table included in Yamane, *Statistics: An Introductory Analysis,* reports significance levels in a t-table of between 25% and 0.05% in one tail. The 10% value I adopted is neither the highest or lowest value in the table.

Q. MR. REIKER'S THIRD CRITICISM OF YOUR TEST IS THAT YOU USED A ONE-TAILED TEST. WHY DID YOU DO THAT?

A. I did it because the issue is not whether there is a small firm effect in general but whether there is a small firm effect for water utilities as well as other companies. The two-tailed test suggested by Mr. Reiker ignores the fact that scholars generally agree there is a small firm effect for stocks in general. The two-tailed test presumes there is a possibility that larger utilities could require a higher return than small utilities. No one, not even Mr. Reiker, has made such a suggestion. His suggestion for a two-tailed test is result-driven and inconsistent with the test that should be made.

Q. AT PAGE 67, MR. REIKER COMPARES THE STUDY YOU PRESENTED TO THE COMMISSION IN 2000 WITH THE STUDY IN TABLE 8. HOW ARE THEY DIFFERENT?

A. The studies are different primarily because I did not include 5-year EPS growth as one of the growth estimates in the more recent study. The goal of my study was to find proxies for forward-looking estimates of growth that investors would have relied upon to price stocks when I only had historical information. In reviewing my earlier study, I noticed that 5-year EPS growth estimates were especially volatile but that when they were included or excluded from the growth rate estimates, the average difference in equity cost estimates changed by only 2 basis points. I do not think investors expect future growth to be as volatile as it was in past five-year periods and thus revised the study.

Mr. Reiker's quotation at page 67 from the Fischer Black article refers to scholars conducting studies with limited data compiled by the University of Chicago Center for Research in Security Prices ("CRSP"). CRSP has done research and improved the quality of the data available to scholars. Clearly Black does not call such improvements "data mining". The changes in data I made from the original study to the current study were also designed to improve the data, in this case data to determine future growth rates from limited data on past growth. The quotation Mr. Reiker presents does not apply to my attempts to improve the quality of the data used in the study.

IV. RESPONSE TO MR. REIKER AND MR. RIGSBY'S CAPM ESTIMATES

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. Mr. Reiker and Mr. Rigsby present equity cost estimates based on the CAPM. In this section of my testimony, I discuss different methods that could be used to implement the CAPM, discuss problems with the methods adopted by Mr. Reiker and Mr. Rigsby and present restatements of their CAPM results using long-term Treasury rates as the risk-free rate.

Q. DO YOU HAVE ANY GENERAL CONCERNS WITH EQUITY COST ESTIMATES BASED ON THE CAPM?

A. Yes. The CAPM is a special case of the risk premium approach,

(1) Equity cost = Bond rate + Company Risk Premium

A general form of the CAPM can be written as

(2) Equity cost = R_Z + Beta x $[E(R_M) - R_Z]$ + SR ,

Where R_Z is the return required by a risk-free asset (an asset with a beta of zero) replaces the bond rate, beta is the risk of the utility relative to changes in market returns, $[E(R_M) - R_Z]$ is a market risk premium over the zero-beta asset and the term "SR" represents any other systematic risks that investors consider in the pricing of stocks. In this general form of CAPM, all of the terms other than R_Z replace the "company risk premium". Both Mr. Reiker and Mr. Rigsby adopt a very specific version of the CAPM written as

(3) Equity cost = R_F + Beta x $[E(R_M) - R_F]$

in which the return for a Treasury security (R_F) is adopted as the measure of the required return for the zero-beta asset and it is assumed that any other systematic risks (SR) are not priced by investors. This form of the CAPM is usually called the Sharpe-Lintner version of CAPM after William Sharpe and John Lintner who originally derived it.

There are problems deciding how to implement the model, problems with making estimates of betas and market risk premiums, and problems with deciding what value to adopt for the risk free (zero-beta) asset. Based on my experience, most regulatory jurisdictions do not give CAPM much weight when determining equity costs. One of the few regulatory commissions that gave CAPM any weight was the Oregon PUC. Recently, the Oregon PUC Staff abandoned presenting equity cost estimates based on the CAPM altogether. If the Sharpe-Lintner version of the model is considered, the measure of R_F is usually a long-term Treasury rate, not either the intermediate-term Treasury rate adopted by Mr. Reiker or the 91-day Treasury rate adopted by Mr. Rigsby.

Q. **WHAT ARE THE ISSUES WITH BETA ESTIMATES?**

A. In general, there are problems with making estimates of betas. But with <u>water</u> utilities the task of estimating betas is especially problematical. Most water utilities are thinly-traded. Over 20 years ago, Professor Roll presented an analysis that showed if betas for thinly-traded stocks were estimated with short-interval data, such as monthly or weekly returns, the beta estimates would be biased downward (Richard Roll, "A Possible explanation of the small firm effect", Unpublished manuscript, University of California, Los Angeles, October, 1980). Ibbotson Associates reached the same conclusion and have suggested using annual data as one means to reduce the bias resulting from smaller stocks being thinly traded (Ibbotson Associates, *Valuation Edition, 2003 SBBI Yearbook,* p.132). In this proceeding, Mr. Rigsby and Mr. Reiker rely upon *Value Line* betas that are based on estimates made with weekly data. All of the water utilities are relatively small companies and thus betas estimates for them are expected to be biased downward.

Q. ARE THERE ISSUES WITH MARKET RISK PREMIUM ESTIMATES?

A. Yes. The task of estimating the current market risk premium is not an easy one. Mr. Reiker wisely presents a relatively wide range of expected market returns to make his estimates. Mr. Rigsby assumes that the average arithmetic return earned in the past is expected to be earned in the future. Whatever the estimate of the market risk premium, it must be internally consistent with the choice of the risk-free (zero-beta) asset also used in the analysis.

Q. IS THERE A PREFERRED METHOD TO IMPLEMENT THE CAPM?

A. Yes. The preferred method to implement the CAPM is to estimate the more general risk premium approach, equation (1). With that approach, the estimated company risk premium provides a direct estimate of the risk premium relevant for a utility and thus it (a) includes (beta times the $[E(R_M) - R_Z]$), (b) includes any required compensation for other systematic risks priced by investors and (c) it reflects the difference between the bond rate and the required return for the zero beta asset. With this approach, there is no need to estimate betas or market risk premiums and there is no reason to determine if "beta risk" is the only risk of relevance to investors holding shares of water utilities. In adopting such company risk premium estimates it is assumed that more reliable estimates of current equity costs can be made by assuming the past relationship between beta, market risk premiums and other systematic risks (whatever they are) continues into the future than to attempt to make individual estimates of each of the inputs (betas, current market risk premium and return on the zero-beta asset) as well as assuming (instead of estimating) what systematic risks are relevant to investors. I have made such risk premium estimates in my direct testimony and have updated them above.

Q. TURN TO YOUR MORE SPECIFIC COMMENTS ABOUT THE CAPM ESTIMATES THAT MR. REIKER AND MR. RIGSBY HAVE MADE. HOW HAVE THEY IMPLEMENTED THE MODEL?

A. Both of them assume that Treasury security rates are a good proxy for the zero-beta asset (though they use different Treasury rates), adopt *Value Line* beta estimates for water utilities as the proxy beta for Arizona Water and compute market risk premium estimates from current and historical data.

Q. HAVE EITHER MR. REIKER OR MR. RIGSBY PRESENTED ANY EVIDENCE THAT THE BETA FOR ARIZONA WATER IS THE SAME AS THE AVERAGE BETA FOR THEIR SAMPLES OF WATER UTILITIES?

A. No, they have not. Arizona Water is not publicly traded and thus does not have an estimated beta that is comparable to the *Value Line* estimates of betas they rely upon. Evidence I have seen indicates Arizona Water's true beta (but not measured beta) is closer to 1.0 than the betas for other water utilities and thus is more risky.

Q. DO YOU HAVE ANY CONCERNS WITH USING THE SHARPE-LINTNER VERSION OF THE CAPM TO MAKE EQUITY COSTS FOR WATER UTILITIES?

A. Yes. The Sharpe-Lintner model was based on an assumption that investors could borrow and lend money at the Treasury bill rate. This is a wrong assumption because it is obvious that we can loan money to the Federal Government at the Treasury bill rate by buying Treasury bills; however, we are all more risky as borrowers than the Federal government and thus cannot borrow money at such a low rate.

Q. WHAT HAPPENS TO THE SPECIFICATION OF CAPM IF A MORE REALISTIC ASSUMPTION IS MADE THAT INVESTORS CANNOT BORROW AND LEND AT THE TREASURY BILL RATE?

A. CAPM calls the relationship between required returns (in a graph, on the vertical or "y" axis) and beta risk (on the horizontal or "x" axis) a "Security Market Line" ("SML"). That SML will slope upward to the right reflecting that as risk increases required returns also increase. If a more realistic assumption about borrowing funds is made, the SML will be a flatter line than the SML of the original Sharpe-Lintner version of CAPM and the intercept (where the SML intersects the "y" axis) will be above the rate the Federal government can obtain when it sells Treasury bills. This change in assumption about borrowing and lending rates is one of the justifications of the "zero-beta" version of CAPM discussed above.

Q. WHAT IS THE IMPLICATION OF THIS CHANGE IN ASSUMPTION FOR EQUITY COST ESTIMATES FOR LOW BETA STOCKS SUCH AS UTILITIES?

A. It means that all stocks have required returns that are closer to the return required for an average stock than the original Sharpe-Lintner model predicted. This is important in the determination of the costs of equity for utilities because it means that the costs of equity for utilities (with betas less than 1.0) are closer to the cost of equity for an average risk stock than the Sharpe-Lintner model predicts.

Q. ARE THERE OTHER THEORETICAL REASONS TO EXPECT THE REQUIRED RETURN FOR AN ASSET WITH A BETA OF ZERO TO BE HIGHER THAN THE RETURN ON TREASURY BILLS?

A. Yes. Fischer Black, co-author of one of the seminal articles that tested the original version of CAPM (Black, Jensen and Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," in Michael Jensen, ed., *Studies in the Theory of Capital*

Markets. New York: Praeger, 1972, pages. 79-121), lists several theoretical reasons for the required return on the zero-beta asset being higher than the Treasury bill rate assumed in the original CAPM. (Fischer Black, "Return and Beta," *Journal of Portfolio Management,* Volume 20, No. 1, Fall 1993, pp. 8-18.)

Q. WHAT HAVE THE EMPIRICAL TESTS OF CAPM GENERALLY FOUND TO BE THE APPROPRIATE RETURN FOR THE RISK-FREE ASSET?

A. Empirical tests of the Sharpe-Lintner model have found that the required return for the zero-beta asset is higher than the Treasury bill rate. Thus, market data indicate the zero-beta specification of CAPM provides a better explanation of the "real world" than the original Sharpe-Lintner model.

Q. YOU MENTIONED PROFESSOR SHARPE WHO WAS ONE OF THE SCHOLARS WHO ORIGINALLY DEVELOPED THE CAPM. WHAT HAS HE HAD TO SAY ABOUT THIS SUBSEQUENT RESEARCH?

A. Professor Sharpe has agreed with those findings and has included them in his book *Investments.* The original Sharpe-Lintner model predicts the intercept of the SML with the vertical axis (where beta is zero) should not be statistically different than the return on Treasury bills. Empirical tests have been made to see if that was the case. William Sharpe reports in both his original textbook (e.g., Sharpe, *Investments,* Third Edition, 1985, page 176) and in a recent update of that textbook (Sharpe, Alexander and Baily, *Investments*, Sixth Edition, 1999, page 246) that major tests of the model have found that the expected return on the risk-free asset is higher than what the original CAPM predicted. Sharpe concluded that

> Many organizations that estimate the SML generally find that it conforms more to the zero-beta CAPM than to the original CAPM. (Sixth Edition, p. 247 see also the Third Edition, page 176).

Also, Fischer Black updated the original tests of the Sharpe-Lintner version of CAPM he conducted with Jensen and Scholes, using data from 1926 to 1991, and found that

> low-beta stocks did better [than the original CAPM would predict] after the [Black, Jensen and Scholes] study period than during it. They did best of all in the most recent decade." (Black (1993), page 16).

Such a result also supports the conclusion that water utilities require a higher equity return than is indicated by the version of the CAPM adopted by Mr. Rigsby and Mr. Reiker.

Q. YOU HAVE TWICE MENTIONED A STUDY BY FISCHER BLACK IN SUPPORT OF THE USE OF THE ZERO-BETA CAPM. IS ACC STAFF AWARE OF THAT STUDY?

A. Yes. Mr. Reiker provides a quote from it at page 67 of his testimony. Staff apparently believes that the Black study is important enough to quote, but ignores the substance of the study. Black found the Sharpe-Lintner version of the CAPM has understated required returns for companies with average betas of .50 during the period 1996-1991 by 3% (if Mr. Rigsby's version of the model is adopted) and by about 2% if the version of the model Mr. Reiker advocates is adopted. Neither Mr. Rigsby nor Mr. Reiker correct for the expected bias in equity cost estimates for water utilities that was found by Black.

Q. DO MR. RIGSBY AND MR. REIKER'S MODIFICATIONS OF THE SHARPE-LINTNER VERSION OF CAPM SOLVE THE PROBLEM OF THE MARKET REQUIRING A RETURN ON THE RISK-FREE ASSET THAT IS HIGHER THAN THE RETURN ON TREASURY BILLS?

A. No. Mr. Rigsby adopted 91-day Treasury bill rates for his CAPM analysis. Such rates are virtually the same as the Treasury rates used in the empirical studies and thus his choice of the Treasury bill rate to make his CAPM estimates will lead to equity cost estimates for water utilities that are expected to be biased downward.

Mr. Reiker modified the Sharpe-Lintner version of CAPM and adopted intermediate-term Treasury securities as the risk-free asset. That choice moved the model in the right direction because, on average, intermediate term Treasury securities provide a return that is approximately 100 basis points higher than Treasury bill returns. (This is the average difference between equity risk premia based on intermediate term Treasury income returns and Treasury bills for the period 1926-2002, Table 9-1, Ibbotson Associates, *SBBI 2003 Yearbook.*) However, the modification did not increase the return on the risk free-asset enough.

Q. WHAT IS THE DIFFERENTIAL BETWEEN TREASURY BILLS AND THE ZERO-BETA ASSET IMPLIED BY THE LITERATURE?

A. The Fama and MacBeth (Eugene Fama and James MacBeth, "Risk Return and Equilibrium: Empirical Tests," *Journal of Political Economy*, May/June 1973, pp. 607-636) analysis which Sharpe reports in *Investments* (Third Edition, page 401) found the required return on the risk-free asset was equivalent to 7.32 percent per year while the average Treasury bill return was but 1.56 percent per year during the period studied. That result suggests that, on average, the zero-beta return is expected to be 576 basis points above Treasury bill returns, 476 basis points above intermediate-term Treasury security yields and 436 basis points above the return investors require for long-term Treasury securities. (Differences based on differences in equity risk premiums reported by Ibbotson Associates in Table 9-1 of their 2003 SBBI Yearbook)

As mentioned above, Fischer Black (1993) updated tests of the CAPM with data for the periods 1931-1991 and 1966-1991. He found a portfolio with a beta of approximately 0.5 required returns in excess of what the traditional Sharpe-Lintner CAPM would predict of 1 percent and 3 percent, respectively. Those results imply a risk-free (zero-beta) asset requires a return in excess of Treasury bills of between 2 percent and 6 percent. (This result is found by extrapolating the excess returns of 1 percent and 3 percent for a stock with a 0.5 beta back to the vertical axis to get 2 percent and 6 percent when beta is zero. At a beta of 1.0, there is no bias.) The modified Sharpe-Lintner version of the CAPM that Mr. Reiker relied upon moved in the correct direction. However the increase of about 100 basis points in the risk-free asset return (and a corresponding decrease in the market risk premium of 100 basis points) is not nearly sufficient to address the theoretical and empirical issues raised by the zero-beta analyses.

Q. HAVE YOU RESTATED MR. REIKER'S AND MR. RIGSBY'S CAPM ANALYSES?

A. Yes. I have restated their results using forecasted values for long-term Treasury rates expected during the period new tariffs are to be in effect. Some analysts have chosen long-term Treasury securities to implement the CAPM by noting that investors price common stocks to reflect long-term returns and thus conclude that the longest Treasury security returns are relevant for determining equity returns. A better reason to make the choice is that empirical tests of the original CAPM discussed above found that the required return for the zero-beta asset is higher than either Treasury bill rates or intermediate-term Treasury rates. Also, the Treasury rate should be for the future, not 2003. My restatement of Mr. Reiker's and Mr. Rigsby's CAPM results are shown below:

Mr. Reiker (water utilities):

Equity cost	=	5.6% +	.59	x 7.0%	=	9.7%
Equity cost	=	5.6% +	.59	x (17.9% - 5.6%)	=	12.9%
				Average	=	11.3%

Mr. Reiker (gas utilities proxy):

Equity cost = 5.6% + .69 x 7.0% - 1.0% = 9.4%

Equity cost = 5.6% + .69 x (17.9% - 5.6%) - 1.0% = 13.1%

Average = 11.3%

Mr. Rigsby:

Equity cost = 5.6% + .63 x (12.2% – 5.6%) = 9.8%

The 7.0% market risk premium in the restatement of Mr. Reiker's CAPM results is from the same table Mr. Reiker relied upon for his premium above intermediate-term rates, but is for the long-term equity risk premium. The forecasted value for the long-term Treasury rate of 5.6% is an average of the Blue Chip consensus forecast of Treasury rates for 2004 and 2005. As I explained above, the use of "actual" current Treasury rates will understate the relevant cost of Treasury securities.

Q. HAVE YOU ALSO APPLIED A "ZERO-BETA" VERSION OF THE CAPM TO RESTATE THEIR CAPM ESTIMATES?

A. No. Empirical tests of the CAPM indicate the expected return for the zero beta asset is, on average, several hundred basis points higher than the average return on long-term Treasury securities. Estimating the cost of equity with such a model would increase the return for the zero beta asset and reduce the market risk premium by the same amount. For stocks, like water utilities stocks, the higher zero beta return would more than offset the lower company risk premium and the indicated cost of equity would be higher. Thus, my restatements of Mr. Reiker and Mr. Rigsby's CAPM approaches above understates the cost of equity that would be estimated if I had adopted a zero-beta model. My choice to use long-term Treasury securities as the proxy for the zero-beta asset provides conservative estimates of water utilities' costs of equity.

Q. IF INVESTORS EXPECT RELATIVELY LOW INFLATION AND INTEREST RATES, WHAT IS THE IMPACT ON THE MARKET RISK PREMIUM?

A. The market risk premium is expected to increase. This conclusion is consistent with the Gordon and Halpern theory and empirical studies that I discussed in my direct testimony. To be conservative, I have not adjusted upward Mr. Rigsby or Mr. Reiker's market risk premium estimates to reflect such an expected increase.

Q. WHY DID YOU USE FORECASTED TREASURY RATES IN YOUR RESTATEMENT?

A. In presenting updates of my risk premium approaches, I explained why the forecasted Baa rates, not current 2003 rates, are appropriate to determine Arizona Water tariffs. The same principle applies to Treasury rates. The equity cost of relevance in this case is Arizona Water's cost of equity when the new rates are expected to be in place. Blue Chip conducts surveys of economists and reports their long term forecasts every six months. Based on the most recent Blue Chip consensus forecast, long-term Treasury rates are expected to average 5.6% during the next two years.

V. RESPONSE TO MR. REIKER'S DCF EQUITY COST ESTIMATES

Q. HAVE YOU RESTATED MR. REIKER'S DCF EQUITY COST ESTIMATES?

A. Yes. Rebuttal Tables 21, 22, 23 and 24 provide the restatement of his DCF equity cost estimates as well as a summary of my restatements of his equity cost estimates for water and gas utilities.

Q. PLEASE BEGIN WITH YOUR COMMENTS ABOUT HIS CONSTANT GROWTH DCF ANALYSES. FOR PURPOSES OF YOUR

RESTATEMENT, HAVE YOU ADOPTED MR. REIKER'S DIVIDEND YIELDS BASED ON SPOT PRICES?

A. Yes. I do not believe spot prices should be adopted to compute dividend yields, but, for purposes of my restatement of his DCF equity cost estimates, I have adopted Mr. Reiker's numbers.

Q. **DO YOU HAVE ANY CONCERNS WITH THE GROWTH RATES HE ADOPTS FOR HIS CONSTANT GROWTH DCF ESTIMATES?**

A. Yes. When an industry is in transition and companies within that industry are in the process of attempting to increase their financial strength, the absolute worst indicator of future growth to use with the constant growth DCF model is past dividend per share ("DPS") growth or near-term forecasts of increases in DPS. In fact, that evidence combined with evidence that earnings per share ("EPS") growth has been and is expected to be more rapid than DPS growth provides investors a basis to expect higher growth in the future. Many water and gas utilities have chosen to grow dividends more slowly than earnings are growing. EPS growth is also expected to grow much faster in the future than DPS. Mr. Reiker reports that has been the case in Schedules JMR-2 and JMR-13. Such choices have been made by the gas and water utilities to increase financial strength and get their finances in order for the future. In particular, water utilities have sought to increase their financial strength in an era of mergers, acquisitions and a future expected to require massive amounts of new capital to fund replacement of an aging infrastructure. Such delays in DPS increases improve the prospects for long-term dividend growth as the utilities increase their retention ratios and set the stage for higher sustainable growth.

Mr. Reiker correctly reports that both the water utility sample and gas utility sample are expected to have EPS growth that will exceed DPS growth. For the water utility sample, EPS growth is expected to be 3 times faster than DPS growth. In the case of the gas utilities, EPS is expected to grow 6 times faster than DPS. See Schedules JMR-2 and JMR-13. As the utilities improve their retention ratios (as EPS grows faster than DPS), investors would recognize that the utilities will be able to grow dividends much faster in the future than in the past. Investors look forward -- not backward -- and would realize the forecasts of slow near-term growth of DPS and past slow growth in DPS are the result of actions taken by the utilities to prepare for the future and that such differential growth in EPS and DPS allows higher dividend growth in the future.

Knowledgeable investors relying on the constant-growth DCF model would not use past DPS growth or forecasts of near-term DPS growth to determine growth. Thus they should not be included in the estimated average of growth rates used to make equity cost estimates for water and gas utilities with the constant-growth DCF model.

Q. ARE THERE OTHER REASONS NOT TO INCLUDE PAST DPS GROWTH?

A. Yes. In a number of places in his testimony, Mr. Reiker acknowledges Professor Myron Gordon to be an authority on the DCF model. Dr. Gordon wrote an article with two other authors (Gordon, Gordon and Gould, "Choice Among Methods of Estimating Share Yield," *Journal of Portfolio Management (Spring 1989)*) ("GG&G") in which he found analysts' consensus forecasts of future EPS growth provided better estimates of DCF growth than did past BR growth, past DPS growth and past EPS growth. In reaching that conclusion, GG&G say the superior performance by [forecasts of earnings growth] should come as no surprise. All four estimates of growth rely upon past data, but in the case of [forecasted earnings growth] a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth. (GG&G, page 54)

To the extent that the past is relevant to the future, it is already in analysts' forecasts.

Q. AT PAGE 44, MR. REIKER STATES HISTORICAL GROWTH RATES ARE RELEVANT FOR A DCF ANALYSIS. DO YOU HAVE ANY OBSERVATIONS ABOUT HIS POINT?

A. Yes. Mr. Reiker has failed to recognize Professor Gordon's point that historical growth would already have been taken into account by professional analysts when they make their forecasts. Thus to the extent that the analysts have already taken historical growth into account in their own forecasts, Mr. Reiker's approach <u>double-counts</u> the past. Worse yet, with respect to past DPS growth, it gives weight to a slow growth rate that, when combined with more rapid EPS growth, actually provides a harbinger of future growth that is expected to be much faster. Analysts are expected to provide unbiased forecasts of the future and to have already taken the past into account. Also, as long as investors expect EPS to grow more rapidly than DPS, the retention ratio and thus potential growth from internal sources will increase. In such a situation, investors would not view near-term DPS growth as an indicator of average constant growth over the life of the security.

Q. DO YOU HAVE ANY EVIDENCE THAT PAST DPS GROWTH AND NEAR-TERM FORECASTS OF DPS GROWTH WOULD NOT BE CONSIDERED BY INVESTORS?

A. Yes. Any "method" used to estimate the cost of equity should provide an equity cost estimate that exceeds the cost of Baa bonds by a reasonable margin. Rebuttal Table 20 compares authorized returns in Arizona to Baa rates to determine the smallest margin that is consistent with past decisions. In making this analysis, I assume -- as I did in the analysis in Table 23 and my Rebuttal Table 14 -- that Baa rates 8 months prior to the order date provide a reasonable proxy for the level of interest rates considered during the proceeding. Rebuttal Table 20 shows the ACC has found margins above Baa rates of between 215 basis points and 466 basis points to be reasonable in the past; thus a margin at least as large as the smallest past margin should be expected. Applying an equity cost estimation method to determine the equity cost for any particular utility in a sample might lead to an equity cost that produces less than a 215 basis point margin above Baa debt, but if the method is a reasonable approach, the data for the whole sample should exceed 9.25% (the bottom of the range of expected Baa rates of 7.1% plus the smallest margin of 2.15%).

Schedules JMR-7 and JMR-18 report dividend yields for the water and gas utilities Mr. Reiker uses in his constant growth DCF model of 3.47% and 4.97%, respectively. Combining those dividend yields with past and forecasted DPS growth rates yield equity cost estimates that don't make any sense. They are as follows:

Water Utilities:

Past DPS growth	3.47% +	2.5%	=	6.0%
Projected DPS growth	3.47% +	2.9%	=	6.4%

Gas Utilities:

Past DPS growth	4.97% +	2.2%	=	7.2%
Projected DPS growth	4.97% +	1.4%	=	6.4%

None of those DCF estimates comes even close to the bottom of the range of 9.25%.

Q. HAVE YOU RESTATED MR. REIKER'S CONSTANT-GROWTH DCF EQUITY COST ESTIMATES WITHOUT INCLUDING PAST DPS

GROWTH AND NEAR-TERM DPS GROWTH IN THE AVERAGE GROWTH RATES?

A. Yes. The restatements are as follows:

$$\text{Equity cost}_{water} = 3.47\% + 6.13\% = 9.6\%$$

$$\text{Equity cost}_{gas} = 4.97\% + 5.95\% = 10.9\%$$

Mr. Reiker would reduce the estimate for the gas utilities by 100 basis points to 9.9%. The revised growth rates are the averages of 10-year EPS growth, projected EPS growth, 10-year intrinsic (sustainable) growth and projected intrinsic (sustainable) growth for the water and gas utilities reported by Mr. Reiker at Schedules JMR-4 and JMR-15, respectively. An equity cost for Arizona Water requires the addition of 100 to 150 basis points to the estimates for the water utilities.

Q. PLEASE TURN TO MR. REIKER'S MULTI-STAGE DCF MODEL. WHAT DID HE DO?

A. Mr. Reiker implemented a two-stage DCF model in which he assumes investors would look at dividend growth for five years (stage-1 growth) and then adopt a growth rate for the economy as a whole for the terminal growth rate (stage-2 growth). He solves for the internal rate of return that makes the current price equal to *Value Line's* forecasts of dividends for the first year, dividends for the next four years based on *Value Line* forecasts of DPS growth and dividends after that first five year period that grow at the terminal growth rate.

Q. HAVE YOU RESTATED HIS MODEL ?

A. Yes. I have restated his analyses for both the water and the gas utilities with a three-stage growth model that incorporates Mr. Reiker's estimates of dividend growth, intrinsic growth and terminal growth. The results of my restatements are shown in Rebuttal Tables 21 and 22.

As I explained above, knowledgeable investors expect the relatively slow near-term growth in DPS will be rewarded by higher future growth as the utilities gain financial strength from growing their retention ratios. A multi-stage growth DCF model should incorporate this reasonable expectation of investors and not immediately go to a final stage growth rate that has nothing to do with the improved financial strength of the utilities. Also, the multi-stage DCF model should be internally consistent with the *Value Line* forecasts Mr. Reiker relies upon to forecast initial DPS growth. *Value Line* provides forecasts of intrinsic growth (Mr. Rigsby and I call this growth, "sustainable growth") for the period 2006 to 2008. Mr. Reiker presumes *Value Line* forecasts of DPS growth are relevant to investors for 2007 and 2008 when investors have better data available. Investors relying on *Value Line* forecasts would more logically assume *Value Line* forecasts of intrinsic growth for the 2006-2008 would be relevant for a number of years following 2006. Mr. Reiker's construction of the multi-stage growth model totally ignores those important forecasts of intrinsic growth. In my restatement, I have assumed Mr. Reiker's estimates of projected intrinsic growth from Schedules JMR-3 and JMR-14, for water and gas utilities, respectively, to determine second-stage growth for ten years following 2006 (2007-2016). My third stage growth rate is the same as Mr. Reiker's second stage growth rate but starts in 2017 instead of year 6 as is assumed by Mr. Reiker.

Q. **HOW DID YOU DETERMINE PROJECTED INTRINSIC GROWTH FOR CONNECTICUT WATER SERVICE, MIDDLESEX WATER AND SJW CORP?**

A. I used the method Mr. Reiker used to estimate DPS growth for those utilities. He assumed the average of DPS growth rates for American States, California Water and Philadelphia Suburban provided a reasonable forecast of the DPS growth rate investors would expect for the remaining three. In making my multi-stage analysis, I adopted Mr. Reiker's approach to estimate initial DPS growth as well as subsequent intrinsic (sustainable) growth.

Q. PLEASE SUMMARIZE HOW YOUR MODEL DIFFERS FROM HIS.

A. I have added a second stage that recognizes both the *Value Line* forecasts of initial DPS growth and subsequent forecasts of intrinsic growth. My second stage growth is internally consistent with the *Value Line* forecasts of DPS and EPS from 2003 to 2006. In making my restatement, I have used Mr. Reiker's estimates of stock prices, next year's DPS estimates, initial DPS growth, intrinsic growth rates and the terminal growth rate of 6.5% he adopts. All of the data that I have used comes from Mr. Reiker's own tables. When *Value Line* did not provide a forecast, I adopted Mr. Reiker's approach and assumed the average for the other water utilities was expected for the ones for which there was no forecast.

Q. WHAT ARE THE RESULTS OF YOUR RESTATEMENT OF HIS MULTI-STAGE DCF MODEL?

A. My results are shown in Rebuttal Tables 21 and 22. For Mr. Reiker's water utilities sample, the average equity cost estimate is 10.1%. For the gas utilities, the average equity cost estimate is 11.1%. Mr. Reiker would reduce the gas utilities equity cost estimate by 100 basis points, thus the restated proxy estimate of the large water utilities benchmark cost of equity made with data for the gas utilities is also 10.1%. Adding the 100 to 150 basis point risk premium to those restated equity cost estimates, indicates a cost of equity range for Arizona Water of 11.1% to 11.6%.

Q. HAVE YOUR PREPARED A SUMMARY OF YOUR RESTATEMENTS OF MR. REIKER'S CAPM AND DCF EQUITY COST ESTIMATES?

A. Yes, I have. Rebuttal Tables 23 and 24 summarize my restatements of his estimates for water utilities and gas utilities estimates, respectively. Based on the method he adopts, the average equity cost estimate for water utilities and average proxy equity cost based on data for the gas utilities are both 10.6%.

VI. RESPONSE TO MR. RIGSBY'S DCF EQUITY COST ESTIMATES

Q. WHAT ARE YOUR PRIMARY CONCERNS WITH MR. RIGSBY'S DCF ANALYSIS?

A. I address two concerns. First, Mr. Rigsby agrees with me that VS growth (external growth) and BR growth (internal growth) should be recognized when determining sustainable growth rate estimates. He has, however, adopted estimates of "S" and a formula to compute "V" that will understate values of VS growth investors could reasonably expect from water utilities. Second, he has underestimated BR growth (growth from internal sources). As a result, he has understated growth and the DCF equity cost estimates. If an estimate of growth used in the DCF model is less than investors expect, the DCF equity cost will be too low.

Q. HOW DOES THE SAMPLE OF WATER UTILITIES HE USES TO DETERMINE DCF EQUITY COSTS COMPARE TO THE ONE YOU USED?

A. He uses the three large water utilities (out of four) I adopted for my analysis.

Q. FIRST, HOW DO MR. RIGSBY'S ESTIMATES OF BR GROWTH FOR HIS THREE UTILITIES COMPARE TO YOUR ESTIMATES OF BR GROWTH?

A. His estimates are of BR growth are 25, 50 and 110 basis points lower than my estimates. His estimates are based on his review of data presented in Schedule WAR–6 and his judgment. The data in WAR-6 includes BR growth rates based on data reported by *Value Line* (in column C of WAR-6 page 1 of 2) that Mr. Rigsby has not adjusted to recognize the *Value Line* convention of reporting ROEs on an end-of-year basis.

Q. HOW DO MR. RIGSBY'S ESTIMATES OF BR GROWTH COMPARE TO MR. REIKER'S PROJECTED BR GROWTH RATRES?

A. The estimates of projected BR growth reported by Mr. Reiker's in Schedule JMR-3 are also higher than the BR growth rates Mr. Rigsby adopts. In one of my restatements of Mr. Rigsby's DCF results, I have adopted the estimates of projected VS and BR growth reported by Mr. Reiker.

Q. TURN TO MR. RIGSBY'S ESTIMATE OF VS GROWTH. EXPLAIN YOUR CONCERNS WITH HIS ESTIMATES OF THE STOCK FINANCING RATE "S"?

A. The approach Mr. Rigsby has taken underestimates the stock-financing rate that rational investors would anticipate. Rebuttal Table 25 shows recent past growth in shares, forecasted future growth in shares and an average of past and future growth in the number of shares as compared to Mr. Rigsby's estimates. Mr. Rigsby's average of estimates for S are less than all three averages of past and future estimates of share growth. For my first restatement of Mr. Rigsby's DCF estimates, I have adopted his estimates of future growth in shares from Schedule WAR-6 page 1 of 2, column F to compute VS growth. This is the only change in the numbers Mr. Rigsby used to make the DCF estimate. With this change alone, his DCF equity cost estimate increases to 10.0%. The revised estimates of S and VS growth are developed in Rebuttal Table 25 and the restatement of his DCF estimate with the revised value for VS growth is shown in Rebuttal Table 26.

Q. WHAT IS THE PROBLEM WITH THE FORMULA HE USES TO COMPUTE V?

A. In estimating V, Mr. Rigsby substitutes his opinion for market data. He opines that ultimately, investors would expect stock prices for regulated utilities to drop to book value (Rigsby, page 16). Thus, instead of using the market prices to determine V called for in a market model, Mr. Rigsby uses an average of the observed market-to-book ratio and a hypothetical market-to-book ratio of 1.0 to compute his estimate of V in VS growth. When the market-to-book ratio is 1.0, V is estimated to be zero and VS growth is also estimated to be zero. If one adopts the concept Mr. Rigsby espouses, it has the affect of assuming investors expect one-half as much VS growth as is revealed by market data.

Q. WHAT ARE THE PROBLEMS WITH HIS ASSUMPTION?

A. The DCF model is a market model. If investors do indeed expect the market-to-book ratio to move ultimately toward 1.0, current prices would <u>already</u> reflect that tendency and no further *ad hoc* adjustment is required. A market model presumes investors have already taken such a possibility into account when they price a utility stock and thus any additional adjustment is unnecessary.

Q. SHOULD MARKET PRICES MOVE TOWARD BOOK VALUES IF A UTILITY'S AUTHORIZED RETURN IS EQUAL TO THE COST OF EQUITY?

A. Not necessarily. I discuss this issue at pages 30 to 33 of my direct testimony and do not repeat that testimony again. Mr. Rigsby did not explain why he disagreed with the points I raised. Table 14 of my direct testimony shows the average market-to-book ratios for water utilities followed by *C. A. Turner Utilities Reports* has been above 1.0 since at least 1991.

Q. IF AN ANALYST INCLUDES AN ESTIMATE OF VS GROWTH THAT UNDERSTATES THE MARKET PRICE, AND THUS THE MARKET-TO-BOOK RATIO INVESTORS ARE WILLING TO PAY TODAY, WOULD THERE HAVE TO BE OTHER ADJUSTMENTS TO THE EQUITY COST

ESTIMATES?

A. Yes. For consistency, dividend yields should also be based on Mr. Rigsby's hypothetical prices. That approach would reduce prices, increase dividend yields and thus increase equity cost estimates. I do not believe DCF estimates should be based on hypothetical prices and thus do not present such an exercise.

Q. DID YOU PREPARE A SECOND RESTATEMENT OF MR. RIGSBY'S DCF APPROACH?

A. Yes. For this restatement, I relied upon estimates of BR growth and VS growth Mr. Reiker presents in Schedule JMR-3 and Mr. Rigsby's estimates of dividend yields. Rebuttal Table 26 shows that if sustainable growth is based on Mr. Reiker's data and not the flawed VS growth and lower BR growth that are based largely on Mr. Rigsby's opinion, the cost of equity for large water utilities is 11.1%. I develop that estimate in Rebuttal Table 26.

Q. HAVE YOU PREPARED A TABLE THAT SUMMARIZES YOUR RESTATEMENTS OF MR. REIKER AND MR. RIGSBY'S EQUITY COST ESTIMATES?

A. Yes, I have. It is Rebuttal Table 27. Based on those restatements of their estimates, Arizona Water's cost of equity falls in a range of 10.6% to 12.8% at this time.

Q. DOES THIS COMPLETE YOUR PREFILED REBUTTAL TESTIMONY?

A. Yes.

EXHIBITS

A

Arizona Water Company

Update Table 11

Average Dividend Yields for Water Utilities Sample

	D_0/P_0	D_0 _a/	3-Month High Stock Price_b/	3-Month Low Stock Price_b/
1 American States	3.55%	$0.88	$26.86	$22.80
2 California Water	4.18%	$1.12	$28.85	$25.10
3 Philadelphia Suburban	2.46%	$0.54	$23.84	$20.63
4 SJW Corp	3.47%	$2.80	$86.49	$75.65
Average	3.41%			

Notes and Sources:
_a/ Dividends paid during last 12 months (as of May 31, 2003)
_b/ Prices during the last 3 months as of May 31, 2002.

7/22/03

Arizona Water Company

Update Table 12

Estimates of Sustainable Growth for the Water Utilities Sample

	Retention Ratios Derived from Value Line Forecasts_a,e/	Forecasted ROE_b,e/	Forecast of BR_c/ Growth	VS Growth_d/	Average Sustainable Growth
1 American States	0.47	10.5%	5.1%	1.0%	6.0%
2 California Water	0.39	10.0%	4.0%	1.6%	5.7%
3 Philadelphia Suburban	0.52	15.0%	8.1%	3.4%	11.5%
4 SJW Corp_e/	0.48	10.6%	5.3%	0.0%	5.3%
Average of column	0.47	11.5%	5.6%	1.5%	7.1%

Notes and Sources:

_a/ Based on Value Line forecasts of DPS and EPS for the period 2006-2008 published at May 2, 2003 or past retention ratios.
_b/ Value Line forecast of ROE if available, otherwise past average earned ROE.
_c/ BR growth adjusted for year-end ROE forecast by Value Line.
_d/ Estimated VS growth derived in Update Table 13.
_e/ Based on historical information for 1996-2002 reported by Value Line.

7/22/03

Arizona Water Company

Update Table 13

Estimate of Expected VS Growth for Water Utilities Sample

	Stock Financing Rate (S)_a/ (a)	Market to Book Ratio_b/ (b)	V (c)	VS growth (d)
1 American States	2.19%	1.81	0.45	0.98%
2 California Water	2.99%	2.19	0.54	1.62%
3 Philadelphia Suburban	4.97%	3.20	0.69	3.42%
4 SJW Corp	0.00%	1.61	0.38	0.00%
Average of Column		2.20	0.51	1.50%

Notes and Sources:
_a/ From Value Line data reported May 3, 2002.
_b/ As reported by C. A. Turner in June 2003.

7/22/03

Arizona Water Company

Update Table 15

Analysts Forecasts of Future Earnings Growth for Water Utilities Sample

	Zacks[a]	Value Line[b]	Average
1 American States	4.5%	6.0%	5.3%
2 California Water	5.0%	9.0%	9.0%
3 Philadelphia Suburban	8.2%	10.0%	9.1%
4 SJW Corp	_c/	_d/	
Averages:	5.9%	8.3%	7.1%

Notes and Sources:

_a/ As reported by Mr. Rigsby in WAR-7.

_b/ Value Line forecasts as of May 2, 2003.

_c/ No forecast reported by either First Call, Multex or Zacks on July 11, 2003.

_d/ Value LIne does not provide forecasts for SJW Corp.

7/22/03

Arizona Water Company

Update Table 4

Beta-[a/] Risk of Gas and Water Utilities Samples

	Reported by Mr. Reiker-[a/]	At the time AWC Filed Direct-[b/]
Gas Distribution Utilities		
1 AGL Resources	0.75	0.60
2 Atmos Energy	0.60	0.55
3 Laclede Gas	0.60	0.55
4 NICOR	0.90	0.60
5 NW Natural	0.60	0.60
6 Peoples Energy	0.75	0.70
7 Piedmont Natural	0.70	0.60
-[d/] South Jersey Industries	0.50	na
8 WGL Holdings	0.65	0.60
Average	0.67	0.60
Water Utilities		
1 American States	0.60	0.65
2 California Water	0.60	0.60
3 Philadelphia Suburban	0.70	0.60
4 SJW Corp	0.50	0.55
Average	0.60	0.60
Difference in average betas	0.072	0.00
Market Risk Premium-[c/]	7.0%	7.0%
Indicated difference in cost of equity (basis points)	51	0

<u>Sources:</u>

_a/ Schedules JMR-5 and JMR-16.
_b/ Table 4 of Zepp Direct Testimony.
_c/ Ibbotson Associates, SBBI Year Book, Table 9-1.
_d/ As estimated by *ValueLine.*

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Arizona Water Company

Update Table 16

DCF Equity Cost Ranges Estimated for Water Utilities Sample and Arizona Water

	D_0/P_0	D_1/P_0 _a/	Growth _b/	Water Utilities Sample Equity Cost	Arizona Water Equity Cost _c/
Bottom of Range	3.41%	3.7%	7.1%	10.8%	11.8%
Top of range	3.41%	3.7%	7.1%	10.8%	12.3%

Notes and Sources:
_a/ Based on $D_1 = D_0 \times (1 + g)$.
_b/ Average of estimated sustainable growth and range of growth predicted by analysts. See Update Tables 12 and 15.
_c/ Water utilities sample equity cost plus 100 to 150 basis points.

7/22/03

Arizona Water Company

Update Table 17

Average Dividend Yields for Gas Utilities Sample

	D_0/P_0	D_0 [a]	3-Month High Stock Price [b]	3-Month Low Stock Price [b]
1 AGL Resources	4.46%	$1.09	$26.98	$22.30
2 Atmos Energy	5.26%	$1.20	$24.98	$20.85
3 Laclede Gas	5.55%	$1.34	$26.92	$21.90
4 NICOR	6.43%	$1.85	$36.30	$23.70
5 NW Natural	4.82%	$1.26	$28.52	$24.13
6 Peoples Energy	5.36%	$2.10	$44.60	$34.93
7 Piedmont Natural	4.48%	$1.63	$39.69	$33.53
8 WGL Holdings	4.81%	$1.27	$28.14	$25.00
Average	5.15%			

Notes and Sources:
_a/ Dividends paid during last 12 months (as of May 31, 2003)
_b/ Prices during the last 3 months as of May 31, 2002.

7/22/03

Arizona Water Company

Update Table 18

Forecasts of Sustainable Growth for Gas Utilities Sample

	Retention Ratios Derived from Value Line Forecasts[a]	Forecasted ROE	Forecast of BR[b] Growth	VS Growth[c]	Average Sustainable Growth
1 AGL Resources	0.48	11.0%	5.4%	0.9%	6.3%
2 Atmos Energy	0.44	14.5%	6.6%	2.8%	9.3%
3 Laclede Gas	0.26	10.5%	2.8%	0.2%	2.9%
4 NICOR	0.38	18.5%	7.2%	0.0%	7.2%
5 NW Natural	0.43	10.0%	4.4%	0.5%	5.0%
6 Peoples Energy	0.39	12.0%	4.8%	0.0%	4.8%
7 Piedmont Natural	0.38	12.5%	4.8%	0.7%	5.5%
8 WGL Holdings	0.45	11.0%	5.0%	0.2%	5.2%
Average of column	0.40	12.5%	5.1%	0.6%	5.8%

Notes and Sources:
_a/ Value Line forecasts of DPS and EPS growth and ROE as of June 20, 2003.
_b/ BR growth adjusted for year-end ROE forecast by Value Line.
_c/ See Update Table 19.

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Arizona Water Company

Update Table 19

Estimate of Expected VS Growth for Gas Utilities Sample

	Stock Financing Rate (S)_a/ (a)	Market to Book Ratio_b/ (b)	V (c)	VS growth (d)
1 AGL Resources	1.86%	1.86	0.46	0.86%
2 Atmos Energy	7.78%	1.55	0.35	2.76%
3 Laclede Gas	0.46%	1.58	0.37	0.17%
4 NICOR	0.00%	2.02	0.50	0.00%
5 NW Natural	1.84%	1.39	0.28	0.52%
6 Peoples Energy	0.00%	1.81	0.45	0.00%
7 Piedmont Natural	1.27%	2.19	0.54	0.69%
8 WGL Holdings	0.59%	1.54	0.35	0.21%
Average of Column		1.74	0.41	0.65%

Notes and Sources:
_a/ From Value Line data reported June 20, 2003.
_b/ As reported by C. A. Turner in June 2003.

7/22/03

Arizona Water Company

Update Table 20

Analysts' Forecasts of Future Earnings Growth for Gas Utilities Sample

	First Call_a/	Value Line_b/	Average
1 AGL Resources	6.0%	8.0%	7.0%
2 Atmos Energy	6.0%	10.0%	8.0%
3 Laclede Gas	4.0%	5.0%	4.5%
4 NICOR	4.5%	3.0%	3.8%
5 NW Natural	5.0%	5.0%	5.0%
6 Peoples Energy	5.0%	4.0%	4.5%
7 Piedmont Natural	5.0%	7.5%	6.3%
8 WGL Holdings	4.0%	7.0%	5.5%
Averages	4.9%	6.2%	5.6%

Notes and Sources:

_a/ First Call average forecasts reported on Internet on July 11, 2003.

_b/ Value Line forecasts as of June 20, 2003.

7/22/03

Arizona Water Company

Update Table 21

DCF Equity Cost Ranges for Water Utilities Sample and Arizona Water
Based on Data for Gas Utilities Sample

	D_0/P_0	D_1/P_0[a]	Growth[b]	Gas Utilities Sample Equity Cost	Benchmark Water Utilities Sample Equity Cost[c]	Arizona Water Equity Cost[d]
Top of range	5.1%	5.4%	5.7%	11.1%	10.6%	11.6%
Bottom of range	5.1%	5.4%	5.7%	11.1%	10.6%	12.1%

Notes and Sources:
_a/ Based on $D_1 = D_0 \times (1 + g)$.
_b/ Average of estimated sustainable growth and range of growth predicted by analysts. See Update Tables 18 and 20.
_c/ Assumes equity cost is 50 basis points lower.
_d/ Water utilities sample equity cost plus 100 to 150 basis points.

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Arizona Water Company

Update Table 22[a]

Water Utility Risk Premiums Computed with Past Water Utilities ROEs and Forecasted Costs of Baa Bonds

Forecasts of Baa Corporate Rate[b]	Estimated Risk Premium[a]	Forecasted Equity Cost for Large Water Utilities	Forecasted Equity Cost for Arizona Water
7.10%	3.91%	11.0%	12.0%
7.70%	3.53%	11.2%	12.7%

Notes and Sources:
a/ Formula from Table 22 of Direct Testimonmy
b/ Blue Chip Long Range Forecast, June 2003.

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Arizona Water Company

Update Table 23

Risk Premium Analysis[a]
Regression Analysis of Risk Premiums Based on Authorized Returns
for Natural Gas Utility Stocks and Baa Corporate Bond Rates

	Equity Cost Estimate		Predicted Premium[a]		Forecasted Baa Corporate Bond Rate[b]
Bottom	10.9%	=	3.83%	+	7.10%
Top	11.2%	=	3.53%	+	7.70%

Estimated Equity Cost for the Average Utility
in Water Utilities Sample:

Bottom	=	10.4%
Top	=	10.7%

Estimated Range of Equity Costs for Arizona
Water Company

Bottom	=	11.4%
Top	=	12.2%

Notes and Sources:
_a/ Source Direct Table 23
_b/ Blue Chip Long Range Forecast, June 2003.

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Arizona Water Company

Update Table 24

Risk Premium Analysis[a]
Comparison of Total Returns on Moody's Natural Gas Stock Index
and Baa Corporate Bond Rates

Average Risk Premium[a] = 3.67%

Equity Cost Forecast	Forecast of Baa Bond Rates[b]	Gas Utility Equity Cost	Benchmark Water Utilities Sample Equity Cost	Arizona Water Equity Cost
Low	7.1%	10.8%	10.3%	11.3%
High	7.7%	11.4%	10.9%	12.4%

Sources and Notes:
a/ Data from Direct Table 24
b/ Range of forecasts for 2004-2005 compiled by Blue Chip, June 2003.

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Arizona Water Company

Update Table 25

Update of Summary Table: Estimated Cost of Equity Ranges for Water Utilites Sample and Arizona Water

	Estimated Benchmark Ranges of Equity Costs for Water Utilities Sample			Estimated Range of Equity Costs for Arizona Water		
Discounted Cash Flow Estimates						
Based on Water Utilities	10.8%	to	10.8%	11.8%	to	12.3%
Based on Gas Utilities	10.6%	to	10.6%	11.6%	to	12.1%
Risk Premium Analyses Estimates						
Based on Water Utilities	11.0%	to	11.2%	12.0%	to	12.7%
Based on Gas Utilities Authorized ROEs	10.4%	to	10.7%	11.4%	to	12.2%
Based on Moody's Gas Utilities Index	10.3%	to	10.9%	11.3%	to	12.4%
Estimated Equity Cost Range for Arizona Water				11.3%	to	12.7%

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B

Arizona Water Company

Rebuttal Table 1

Authorized Returns, Realized Returns and Forecasted ROEs for Recent Periods

	Mr. Reiker's Sample of Water Utilities		Value Line
			Forecasts of ROE
Year	Authorized ROEs	Actual ROEs	2 Years into the Future
1997	11.18%	11.82%	
1998	11.06%	10.90%	
1999	11.12%	10.59%	11.00%
2000	11.12%	9.75%	11.00%
2001	10.86%	10.27%	11.00%
2002	10.62%	10.58%	10.50%
2003	10.59%	10.60%	11.00%
Average	10.93%	10.64%	10.90%
RUCO/Staff	9.20%	9.20%	9.20%
Difference	1.73%	1.44%	1.70%

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Rebuttal Table 2

Response to Mr. Reiker's Testimony at Page 50:
Work Papers that Were Available But not Requested

A. Authorized ROEs[a]

	AWK	AWR	CWT	CTWS	MSEX	PSC	SJW	Average
1991	12.81	12.00	12.25	12.70	12.30	12.70	12.25	12.43
1992	12.16	11.75	12.25	12.70	12.30	12.00	11.75	12.13
1993	12.16	11.75	12.25	12.70	12.30	12.00	11.75	12.13
1994	11.58	10.10	11.00	12.70	11.50	12.00	11.75	11.52
1995	11.58	10.50	11.00	12.70	11.50	12.00	11.75	11.58
1996	11.58	10.40	10.30	12.70	11.50	12.00	10.20	11.24
1997	11.16	10.40	10.30	12.70	11.50	11.25	10.20	11.07
1998	11.21	10.40	10.30	12.70	12.05	11.05	10.20	11.13
1999	11.21	10.40	10.30	12.70	12.05	11.05	10.20	11.13
2000	11.02	10.00	10.48	12.70	11.15	10.65	10.20	10.89
Average								11.52

B. Return on Average Common Equity [b]

	AWK	AWR	CWT	CTWS	MSEX	PSC	SJW	Average
1991	12.90	11.80	11.80	5.70	12.40	10.90	18.50	12.00
1992	11.20	10.50	11.80	4.80	11.00	10.60	13.70	10.51
1993	11.50	12.50	12.40	10.20	12.90	11.40	10.30	11.60
1994	10.70	10.00	12.30	10.80	12.20	9.50	9.50	10.71
1995	11.20	10.00	12.40	11.70	12.00	10.60	10.00	11.13
1996	9.60	12.40	12.10	11.80	10.60	15.50	9.20	11.60
1997	10.40	14.20	12.10	12.10	11.50	11.40	9.30	11.57
1998	10.60	10.90	12.10	12.40	9.70	11.20	9.50	10.91
1999	8.50	11.20	12.00	9.90	11.20	11.00	10.10	10.56
2000	9.60	10.10	12.30	12.40	7.50	7.40	9.40	9.81
Average								11.04
Difference between Authorized and Realized ROEs								0.48

Notes and Sources:
a/ As reported by C. A. Turner Utilty Reports
b/ As reported by the California PUC Staff. CPUC Staff reported the sources was MSN Money Central 5/31/01.

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Arizona Water Company

Rebuttal Table 3

Equity Risk Premium Analysis Suggested by Mr. Reiker
in Direct Testimony at Page 53

Year	Equity Cost Estimates for Large Water Utilities	Baa Rate	Risk Premium
1987	14.24%	10.58%	3.66%
1988	13.48%	10.83%	2.65%
1989	13.84%	10.18%	3.66%
1990	13.87%	10.36%	3.51%
1991	13.67%	9.80%	3.87%
1992	12.50%	8.98%	3.52%
1993	11.30%	7.93%	3.37%
1994	10.70%	8.63%	2.07%
1995	10.55%	8.20%	2.35%
1996	9.88%	8.05%	1.83%
1997	8.40%	7.87%	0.53%
Average			2.82%

	Baa Range	Equity Cost
Baa Rates -- bottom of range	7.1%	9.9%
Baa Rates -- top of range	7.7%	10.5%

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Rebuttal Table 4

Calculation of Unlevered betas and Implied Equity Ratios with
Market and Book Values for Equity

Value Line betas: JMR-5 and JMR-9 data

			Book Values		Market Values		
	Market betas	tax rate	equity ratio	Bu	Market to-Book	equity ratio	revised Bu
American States	0.60	0.389	0.480	0.36	1.81	0.63	0.44
California Water	0.60	0.397	0.443	0.34	2.19	0.64	0.45
Connecticut Wtr Service	0.60	0.338	0.552	0.39	2.50	0.76	0.49
Middlesex Water	0.55	0.333	0.466	0.31	2.29	0.67	0.41
Philadelphia Suburban	0.70	0.385	0.458	0.41	3.20	0.73	0.57
SJW Corp	0.50	0.404	0.583	0.35	1.61	0.69	0.40
Average	0.59		0.50	0.36		0.68	0.46

Unadjusted betas: JMR-9 data

	Raw betas	tax rate	equity ratio	Bu	Market to-Book	equity ratio	revised Bu
American States	0.37	0.389	0.480	0.22	1.81	0.63	0.27
California Water	0.37	0.397	0.443	0.21	2.19	0.64	0.27
Connecticut Wtr Service	0.37	0.338	0.552	0.24	2.50	0.76	0.30
Middlesex Water	0.30	0.333	0.466	0.17	2.29	0.67	0.23
Philadelphia Suburban	0.52	0.385	0.458	0.30	3.20	0.73	0.42
SJW Corp	0.22	0.404	0.583	0.15	1.61	0.69	0.17
Average	0.36		0.50	0.22		0.68	0.28

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Arizona Water Company

Rebuttal Table 5

Authorized ROE Margins Above Baa Rates
in Recent Arizona Corporation Commision Cases

Date of Decision[a]	Authorized ROE	Baa Rate During[b] Proceeding	Margin
May-97	10.50%	8.35%	2.15%
May-97	11.00%	8.35%	2.65%
September-97	11.50%	8.09%	3.41%
July-98	11.30%	7.42%	3.88%
July-99	11.00%	7.34%	3.66%
July-99	12.00%	7.34%	4.66%
January-00	11.75%	7.72%	4.03%
June-00	11.50%	8.38%	3.12%
October-01	11.00%	7.87%	3.13%
December-01	10.25%	8.07%	2.18%
Average		7.89%	3.29%
Lowest margin			2.15%
Largest Margin			4.66%

Notes and Sources:

a/ Decisions reported in Table 10 of Zepp Direct Testimony.

b/ Based on interest rates prevailing 8 months prior to date of order.

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Arizona Water Company

Rebuttal Table 6: Multi-Stage DCF Estimates
Sample Water Companies

Line No.	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
								Stage 1	Stage 2 Projected	Stage 3	
		Current Mkt. Price (P_o)-a/	Stage 1 growth (2004-2006)			Stage 2 growth (2007-2016)		Initial growth-b/ (2004-2006)	Intrinsic growth-c/ (next 10 years)	Terminal growth-d/ (future years)	Equity Cost Estimate (K)
1			d_{2004}-a/	d_{2005}	d_{2006}	d_{2007}	d_{2016}				
2											
3	American States Water	26.0	0.88	0.91	0.93	0.99	1.70	2.88%	6.20%	6.5%	9.6%
4	California Water	26.9	1.12	1.13	1.15	1.19	1.71	1.16%	4.10%	6.5%	9.7%
5	Connecticut Water Services	25.4	0.85	0.88	0.90	0.97	1.91	3.10%	7.80%	6.5%	10.0%
6	Middlesex Water	22.1	0.88	0.91	0.94	1.01	1.98	3.10%	7.80%	6.5%	10.6%
7	Philadelphia Suburban	23.2	0.58	0.61	0.64	0.73	2.18	5.27%	13.00%	6.5%	10.4%
8	SJW Corp.	85.5	2.95	3.04	3.14	3.38	6.65	3.10%	7.80%	6.5%	10.1%
13										Average	10.1%
14											
15	Sources:										
16	a/ Schedule JMR-6										
17	b/ Schedule JMR-6										
18	c/ Schedule JMR-3. Relatively slow Stage 1 growth permits the higher intrinsic growth in Stage 2.										
19	d/ Schedule JMR-6										
20											

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Arizona Water Company

Rebuttal Table 7: Multi-Stage DCF Estimates
Sample Gas Utilities

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
				Stage 1 growth (2004-2006)		Stage 2 growth (2007-2016)		Stage 1 Initial growth[b/] (2004-2006)	Stage 2 Projected Intrinsic growth[c/] (next 10 years)	Stage 3 Terminal growth[d/] (future years)	Equity Cost Estimate (K
Line No.		Current Mkt. Price (P_o)[a/]	d_{2004}[a/]	d_{2005}	d_{2006}	d_{2007}	d_{2016}				
1	AGL Resources	25.4	1.12	1.12	1.12	1.20	2.15	0.00%	6.8%	6.5%	10.5%
2	Atmos Energy	23.1	1.21	1.24	1.28	1.37	2.70	2.66%	7.8%	6.5%	11.8%
3	Cascade Natural Gas	18.7	0.96	0.97	0.97	1.05	2.14	0.69%	8.2%	6.5%	11.7%
4	Laclede Group	24.2	1.34	1.35	1.36	1.41	1.98	0.74%	3.8%	6.5%	10.6%
5	Nicor Inc.	31.2	1.86	1.95	2.05	2.19	4.03	4.91%	7.0%	6.5%	12.5%
6	Northwest Natural Gas	26.2	1.27	1.29	1.30	1.39	2.42	1.29%	6.4%	6.5%	10.9%
7	Peoples Energy	39.9	2.12	2.15	2.17	2.28	3.60	1.22%	5.2%	6.5%	10.9%
8	Piedmont Natural Gas	37.4	1.66	1.72	1.77	1.91	3.81	3.37%	7.9%	6.5%	11.1%
9	Southwest Gas	20.6	0.82	0.82	0.82	0.88	1.59	0.00%	6.8%	6.5%	10.1%
10	WGL Holdings	26.5	1.28	1.29	1.31	1.39	2.50	1.02%	6.7%	6.5%	10.9%
										Average	11.1%

Sources:

a/ Schedule JMR-17
b/ Schedule JMR-17
c/ Schedule JMR-14. Relatively slow Stage 1 growth permits the higher intrinsic growth in Stage 2.
d/ Schedule JMR-17

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Arizona Water Company

Rebuttal Table 8

Revisions of Mr. Reiker's Final Cost of Equity Estimates
for the Sample Water Companies

Line No.	[A]	[B]		[C]		[D]		[E]
	Constant Growth DCF			D_1/P_0	+	g a/	=	k
1	Constant Growth DCF Estimate			3.47%	+	6.13%	=	9.6%
2	Multi-Stage DCF Estimate						=	10.1%
3						Average		9.8%
	CAPM Approach:	R_F b/	+	β	x	MRP_{RF}	=	k
4	Historical Market Risk Premium	5.6%	+	0.59	x	7.0%	=	9.7%
5	Current Market Risk Premium	5.6%	+	0.59	x	12.3%	=	12.9%
6	Average of CAPM Estimates							11.3%
7	Average of DCF and CAPM Approaches							10.6%

Notes:
a/ Average of all of Mr. Reiker's DCF growth rates other than those based on past and forecasted dividends per share.
b/ Average of Blue Chip forecasts for long-term Treasury securites for 2004-2005.

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Arizona Water Company

Rebuttal Table 9

Revisions of Mr. Reiker's Final Cost of Equity Estimates
for the Sample Gas Utilities

Line No.	[A]	[B]		[C]		[D]		[E]	[F]
	Constant Growth DCF			D_1/P_0	+	g [a/]	=	k	Proxy for Large Water Utilities
1	Constant Growth DCF Estimate			4.97%	+	5.95%	=	10.9%	9.9%
2	Multi-Stage DCF Estimate						=	11.1%	10.1%
3						Average		11.0%	10.0%
	CAPM Approach:	R_F [b/]	+	β	x	MRP_{RF}	=	k	Proxy - k
4	Historical Market Risk Premium	5.6%	+	0.69	x	7.0%	=	10.4%	9.4%
5	Current Market Risk Premium	5.6%	+	0.69	x	12.3%	=	14.1%	13.1%
6	Average of CAPM Estimates							12.3%	11.3%
7	Average of DCF and CAPM Approaches							11.6%	10.6%

Notes:
a/ Average of all of Mr. Reiker's DCF growth rates other than those based on past and forecasted dividends per share.
b/ Average of Blue Chip forecasts for long-term Treasury securites for 2004-2005.

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Arizona Water Company

Rebuttal Table 10

Analysis of Estimates of Mr. Rigsby's Estimates of Share Growth and Restatement of VS Growth

	Growth in Number of Shares			
	Past[a/] (A)	Forecast[b/] (B)	Average (C)	Mr. Rigsby[c/] (D)
1 American States	2.5%	2.1%	2.3%	0.3%
2 California Water	0.2%	4.4%	2.3%	1.0%
3 Philadelphia Suburban	10.9%	2.0%	6.5%	1.8%
Average	4.5%	2.8%	3.7%	1.0%

	Restatement of VS Growth		
	V	S	VS
1 American States	0.41	2.05%	0.84%
2 California Water	0.45	4.37%	1.94%
3 Philadelphia Suburban	1.03	2.00%	2.06%
Average			1.62%

Notes and Sources:
a/ For the period 1997 to 2002.
b/ For the period 2002 to 2007.
c/ Schedule WAR-5, page 2 of 2.

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Arizona Water Company

Rebuttal Table 11

Restatement of Mr. Rigsby's DCF Estimates

A. Revise Mr. Rigsby's Estimate of the stock financing rate[a/]

	Internal Growth (BR)	External Growth (VS)	Dividend Growth (g)	Diviend Yield	DCF Cost of Equity Capital
1 American States	4.60%	0.84%	5.44%	3.41%	8.85%
2 California Water	3.75%	1.94%	5.69%	4.03%	9.72%
3 Philadelphia Suburban	7.00%	2.06%	9.06%	2.43%	11.49%
Average					10.0%

B. Adopt Mr. Reiker's estimates of BR and VS growth[b/]

	Internal Growth[b/] (BR)	External Growth[b/] (VS)	Dividend Growth[b/] (g)	Mr. Rigsby's Dividend Yield	DCF Cost of Equity Capital
American States	5.00%	1.20%	6.20%	3.41%	9.61%
California Water	4.00%	0.10%	4.10%	4.03%	8.13%
Philadelphia Suburban	8.00%	5.00%	13.00%	2.43%	15.43%
Average					11.1%

Notes and Sources:
a/ Value of "s" is revised in Rebuttal Table 10.
b/ Forecasts of BR and VS growth as reported in Schedule JMR-3.

7/22/2003

Arizona Water Company

Rebuttal Table 12

Summary of Restatements of Estimated Cost of Equity Presented
by Mr. Reiker and Mr. Rigsby for Large Water
Utilites Samples and Arizona Water

	Estimated Benchmark Ranges of Equity Costs for Water Utilities Sample			Estimated Range of Equity Costs for Arizona Water		
Discounted Cash Flow Estimates						
Mr. Reiker (gas and water)	9.6%	to	10.1%	10.6%	to	11.6%
Mr. Rigsby	10.0%	to	11.1%	11.0%	to	12.6%
Estimates based on the CAPM						
Mr. Reiker (gas and water)	11.3%	to	11.3%	12.3%	to	12.8%
Mr. Rigsby	9.8%	to	9.8%	10.8%	to	11.3%
Estimated Equity Cost Range for Arizona Water				10.6%	to	12.8%

7/26/03

C

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 903

In the Matter of an Investigation)
Into Policy Issues and Procedures)
Associated with Recovery of)
Purchased Gas Costs By Oregon's)
Regulated Gas Distribution Utilities.)

SWORN TESTIMONY
OF
DR. THOMAS M. ZEPP

JANUARY 21, 1999

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number out; and then let's say you put in the number 10 percent, and you get a second number out: Is the adjustment in basis points the same for the 4 percent as the 10 percent?

A. No.

Q. And how do the -- how does the adjustment differ? For example, I guess I'm trying to conclude, is the adjust MENT greater for higher interest rates than for lower interest rates?

A. The adjustment in basis points --

Q. Yes, exactly.

A. -- would be greater.

Q. For higher interest rates?

A. Yes, would be.

Q. Okay. On page 18 on line 2, you indicate your conclusion that, if investors could have information only on EPS -- and that stands for earnings per share growth, I assume -- or only on DPS -- which I assume is dividends per share growth -- investors would prefer the information about EPS growth.

Are you saying that investors give equal weight to earnings per share historical data in forecasts, and dividends per share of historical data in forecasts, in forming their expectations of dividend growth? Or are you saying that, if you had both of those sets of information, investors would prefer earnings per share?

MS. ACKERMAN: That was a long question. Do you want it broken up?

THE WITNESS: Well, it was a question that didn't refer to the testimony that's stated here. I'm -- I really have no change in the testimony. If you have a different question than what's in the testimony, that's another matter, but I think the testimony is clear.

BY MR. THORNTON:

Q. Okay. Well, I guess I'm not understanding it. If you have earnings per share growth information and dividends per share growth information, which sets of information do investors prefer, according to you?

A. According to me, investors would look at both, but this particular testimony here refers to your testimony, in which you didn't look at earnings per share growth. And my point is, if you're only going to look at one -- in my view, if you were only going to look at one, investors would look at earnings per share growth. That's the testimony, and I still stand by that testimony, but as I've stated, I would look at both.

Q. And just to clarify and give a context to the question, what is the purpose of looking at the information?

MR. GRAHAM: And which information are we talking about, the earnings per share growth?

MR. THORNTON: The earnings per share growth or dividends per share growth.

Q. I mean, why do we look at it?

A. To ultimately forecast dividend growth in the long term.

Q. Or could you also conclude to -- ultimately to estimate investors' forecasts of dividend growth?

A. Yes.

Q. Okay. On page 17, the page just before, on line 18 you indicate that available evidence indicates that they -- meaning the investors -- would look at earnings per share growth. And what is that evidence?

A. It's stated in the next two sentences.

Q. So --

A. That investors are willing to pay for publications such as the S & P Earnings Guide.

Q. Okay. Page 28, on page 28, what is your evidence -- and this is, excuse me, the Q and A beginning on line 10. What is your evidence that including global market returns would increase rather than decrease overall market returns? By "overall market returns" I mean we're technically referring to the efficient portfolio.

A. I would have to get that for you. My recollection -- I've provided that in data responses in the past. It's chapter 10 of a textbook. I'm -- to my recollection Elton and Gruber wrote it, but I would have to check on that, but it is a textbook.

MR. THORNTON: So how do we arrange that?

MR. GRAHAM: Well, let me do some follow-up here. How long would it take you to find out which textbook that is?

THE WITNESS: I'd have to go back through cases, and they are probably four or five years old. But I should -- hopefully I still have it in my work papers. It may have been submitted in a prior Northwest Natural case.

MR. GRAHAM: Do you think that you could

NORTH-HOLLAND

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The QUARTERLY REVIEW of ECONOMICS And FINANCE

Short communication

Utility stocks and the size effect—revisited

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Abstract

Wong concluded there is weak empirical support that firm size is a missing factor from the capital asset pricing model for industrial stocks but not for utility stocks. Her weak results, however, do not rule out the possibility of a small firm effect for utilities. The issue she addressed has important financial implications in regulated proceedings that set rates of return for utilities. New studies based on different size water utilities are presented that do support a small firm effect in the utility industry.

Keywords: Utility stocks; Beta risk; Firm size

Annie Wong concludes there is some weak evidence that firm size is a missing factor from the capital asset pricing model ("CAPM") for industrial stocks but not for utility stocks (Wong, 1993, p. 98). This "firm size effect" is an observation that small firms tend to earn higher returns than larger firms after controlling for differences in estimates of beta risk in the CAPM. Wong notes that if the size effect exists, it has important implications and should be considered by regulators when they determine fair rates of return for public utilities. This paper re-examines the basis for her conclusions and presents new information that indicates there is a small firm effect in the utility sector.

1. Reconsideration of the evidence provided by Wong

Wong relies on Barry and Brown (1984) and Brauer (1986) to suggest the small firm effect may be explained by differences in information available to investors of small and large firms.

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PII: S1062-9769(02)00172-2

She states that requirements to file reports and information generated during regulatory proceedings indicate the same amount of information is available for large and small utilities and thus, if the differential information hypothesis explains the small firm effect, then the uniformity of information available among utility firms would suggest the size effect should not be observed in the utility industry. But contrary to the facts she assumes, there are differences in information available for large and small utilities. More parties participate in proceedings for large utilities and thus generate more information. Also, in some jurisdictions smaller utilities are not required to file all of the information that is required of larger firms. Thus, if the small firm effect is explained by differential information, contrary to Wong's hypothesis, differences in available information suggests there is a small firm effect in the utility industry. Wong did not discuss other potential explanations of the small firm effect for utilities.[2]

Wong's empirical results are not strong enough to conclude that beta risks of utilities are unrelated to size. In the period 1963–1967, when monthly data were used to estimate betas, her estimates of utility betas as well as industrial betas increased as the size of the firms decreased, but she did not find the same inverse relationship between size and beta risk for utilities in other periods. Being unable to demonstrate a relationship between size and beta in other periods may be the result of Wong using monthly, weekly and daily data to make those beta estimates. Roll (1980) concluded trading infrequency seems to be a powerful cause of bias in beta risk estimates when time intervals of a month or less are used to estimate betas for small stocks. When a small stock is thinly traded, its stock price does not reflect the movement of the market, which drives down the apparent covariance with the market and creates an artificially low beta estimate.

Ibbotson Associates (2002) found that when annual data are used to estimate betas, beta estimates for the smaller firms increase more than beta estimates for larger firms. Table 1 compares Value Line (2000) beta estimates for three relatively small water utilities that are made with weekly data and an adjusted beta estimated with pooled annual data for the utilities for the 5-year period ending in December 2000. In making the latter estimate, it is assumed that the underlying beta for each of water utilities is the same. The t-statistics for the unadjusted beta

Table 1
Beta estimates reported by Value Line and estimated with pooled annual returns for relatively small water utilities

	Value Line[a]	Estimated with annual data[b]
Connecticut Water Service	0.45	
Middlesex Water	0.45	
SJW Corporation	0.50	
Average	0.47	0.78
t-statistic		2.72[c,d]

[a] As reported in Value Line (2000). Betas estimated with 5 years of weekly data.

[b] Estimated with pooled annual return premiums for the 5-year period ending December 2000. Proxy market returns are total returns for the S&P 500 index. Dummy variable in 1999 to reflect the proposed acquisition of SJW Corporation included in analysis.

[c] Significant at the 95% level.

[d] The t-statistic for the null hypothesis that the true beta is 0.18 (the derived unadjusted Value Line beta) when the estimated betas is 0.65 (the unadjusted estimated beta) is 1.97. It is significant at the 95% level.

estimate is reported in parentheses. As was found by Ibbotson Associates (2002) for stocks in general, when annual data are used to estimate betas for small utility stocks, the beta estimate increases.

Wong used the Fama and MacBeth (1973) approach to estimate how well firm size and beta explain future returns in four periods. She reports weak empirical results for both the industrial and utility sectors. In every one of the statistical results reported for utilities, the coefficient for the size effect has a negative sign as would be expected if there is a size effect in the utility industry but only one of the results was found to be statistically significant at the 5% level. With the industrial sector, though she found two cases to have a significant size effect, a negative sign for the size coefficient occurred only 75% of the time. What is puzzling is that with these weak results, Wong concludes the analysis provides support for the small firm effect for the industrial industry but no support for a small firm effect for the utility industry.

2. New evidence on risk premiums required by small utilities

Two other studies support a conclusion that small utilities are more risky than larger ones. A study made by Staff of the Water Utilities Branch of the California Public Utilities Commission Advisory and Compliance Division (CPUC Staff, 1991) used proxies for beta risk and determined small water utilities were more risky than larger water utilities. Part of the difficulty with examining the question of relative risk of utilities is that the very small utilities are not publicly-traded. This CPUC Staff study addressed that concern by computing proxies for beta risk estimated with accounting data for the period 1981–1991 for 58 water utilities. Based on that analysis, CPUC Staff concluded that smaller water utilities were more risky and required higher equity returns than larger water utilities. Following 8 days of hearings and testimony by 21 witnesses regarding this study, it was adopted by the California Public Utilities Commission in CPUC Decision 92-03-093, dated March 31, 1992.

Table 2 provides the results of another study of differences in required returns estimated from discounted cash flow ("DCF") model estimates of the costs of equity for water utilities of different sizes. The study compares average estimates of equity costs for two smaller water utilities, Dominguez Water Company and SJW Corporation, with equity cost estimates for two larger companies, California Water Service and American States Water, for the period 1987–1997. All four utilities operated primarily in the same regulatory jurisdiction during that period. Estimates of future growth are required to make DCF estimates. Gordon, Gordon, and Gould (1989) found that a consensus of analysts' forecasts of earnings per share for the next 5 years provides a more accurate estimate of growth required in the DCF model than three different historical measures of growth. Unfortunately, such analysts' forecasts are not generally available for small utilities and thus this study assumes, as was assumed by staff at the regulatory commission, that investors relied upon past measures of growth to forecast the future. The results in Table 2 show that the smaller water utilities had a cost of equity that, on average, was 99 basis points higher than the average cost of equity for the larger water utilities. This result is statistically significant at the 90% level. In terms of the issues being addressed by Wong, the 99 basis points could be the result of differences in beta risk, the small firm effect or some combination of the two.

Table 2
Small firm equity cost differential: case study based on a comparison of DCF equity cost estimates for larger and smaller California water utilities (1987–1997)

	Larger water utilities[a]			Smaller water utilities[b]			Smaller utilities minus larger utilities
	D_0/P_0 (%)	Estimated growth (%)[c]	Equity cost estimate (%)[d]	D_0/P_0 (%)	Estimated growth (%)[c]	Equity cost estimate (%)[d]	
1987	6.60	7.17	14.24	5.38	10.06	15.98	1.74
1988	6.75	6.30	13.48	5.81	9.08	15.42	1.94
1989	7.10	6.30	13.84	6.47	7.00	13.93	0.09
1990	7.24	6.19	13.87	6.96	7.51	14.99	1.11
1991	6.94	6.29	13.67	6.64	6.24	13.30	−0.36
1992	6.18	5.96	12.50	6.50	6.71	13.65	1.14
1993	5.32	5.68	11.30	5.49	6.31	12.15	0.85
1994	6.03	4.40	10.70	5.80	4.86	10.94	0.25
1995	6.44	3.86	10.55	6.44	4.88	11.64	1.09
1996	5.60	4.06	9.88	5.77	5.58	11.67	1.79
1997	4.93	3.31	8.40	4.52	4.89	9.64	1.23
Averarage difference							0.99
t-statistic							1.405[e]

Limited to period for which Dominguez Water Company data were available. 1998 excluded due to pending buyout.

[a] American States Water and California Water Service.

[b] Dominguez Water Company and SJW Corporation.

[c] Average of 5- and 10-year dividends per share growth, 10-year earnings per share growth and estimates of sustainable growth from internal and external sources for the most recent 10-year period when data are available (1991–1997), otherwise most recent 5-year period (1987–1990).

[d] DCF equity cost as computed by California PUC staff: $k = (D_0/P_0) \times (1 + g) + g$.

[e] Significant at the 90% level.

3. Concluding remarks

Wong's concluding remarks should be re-examined and placed in perspective. She noted that industrial betas tend to decrease with increases in firm size but the same relationship is not found in every period for utilities. Had longer time intervals been used to estimated betas, as was done in Table 1, she may have found the same inverse relationship between size and beta risk for utilities in other periods. She also concludes "there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not the utility stocks" (Wong, 1993, p. 98), but the weak evidence provides little support for a small firm effect existing or not existing in either the industrial or utility sector. Two other studies discussed here support a conclusion that smaller water utility stocks are more risky than larger ones. To the extent that water utilities are representative of all utilities, there is support for smaller utilities being more risky than larger ones.

Notes

1. Vice President.
2. The small firm effect could also be a proxy for numerous other omitted risk differences between large and small utilities. An obvious candidate is differentials in access to financial markets created by size. Some very small utilities are unable to borrow money without backing of the owner. Other small utilities are limited to private placements of debt and have no access to the more liquid financial markets available to larger utilities.

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Introduction to Statistics

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University of Florida

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Thus, we estimate the difference in mean time to assemble, $\mu_1 - \mu_2$, to fall in the interval -1.02 to 8.34. Note that the interval width is considerable and that it would seem advisable to increase the size of the samples and re-estimate.

Before concluding our discussion it is necessary to comment on the two assumptions upon which our inferential procedures are based. Moderate departures from the assumption that the populations possess a normal probability distribution do not seriously affect the distribution of the test statistic and the confidence coefficient for the corresponding confidence interval. On the other hand, the population variances should be nearly equal in order that the aforementioned procedures be valid.

If there is reason to believe that the population variances are unequal, an adjustment must be made in the test procedure and the corresponding confidence interval. We omit a discussion of these techniques but refer the interested reader to texts by Li or Anderson and Bancroft.

A procedure will be presented in Section 9.7 for testing an hypothesis concerning the equality of two population variances.

9.5 A Paired Difference Test

A manufacturer wished to compare the wearing qualities of two different types of automobile tires, A and B. To make the comparison, a tire of type A and one of type B were randomly assigned and mounted on the rear wheels of each of five automobiles. The automobiles were then operated for a specified number of miles and the amount of wear was recorded for each tire. These measurements appear in Table 9.3. Do the data present sufficient evidence to indicate a difference in the average wear for the two tire types?

Table 9.3

AUTOMOBILE	A	B
1	10.6	10.2
2	9.8	9.4
3	12.3	11.8
4	9.7	9.1
5	8.8	8.3
	$\bar{x}_1 = 10.24$	$\bar{x}_2 = 9.76$

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Analyzing the data, we note that the difference between the two sample means is $(\bar{x}_1 - \bar{x}_2) = .48$, a rather small quantity, considering the variability of the data and the small number of measurements involved. At first glance it would seem that there is little evidence to indicate a difference between the population means, a conjecture which we may check by the method outlined in Section 9.3.

The pooled estimate of the common variance, σ^2, is

$$s^2 = \frac{\sum_{i=1}^{n_1}(x_i - \bar{x}_1)^2 + \sum_{i=1}^{n_2}(x_i - \bar{x}_2)^2}{n_1 + n_2 - 2} = \frac{6.932 + 7.052}{5 + 5 - 2} = 1.748,$$

and

$$s = 1.32.$$

The calculated value of t used to test the hypothesis that $\mu_1 = \mu_2$ is

$$t = \frac{(\bar{x}_1 - \bar{x}_2)}{s\sqrt{\frac{1}{n} + \frac{1}{n}}} = \frac{10.24 - 9.76}{1.32\sqrt{\frac{1}{5} + \frac{1}{5}}} = .58,$$

a value that is not nearly large enough to reject the hypothesis that $\mu_1 = \mu_2$.

The corresponding 95% confidence interval is

$$(\bar{x}_1 - \bar{x}_2) \pm t_{\alpha/2}s\sqrt{\frac{1}{n_1} + \frac{1}{n_2}} = (10.24 - 9.76) \pm (2.306)(1.32)\sqrt{\frac{1}{5} + \frac{1}{5}}$$

or -1.45 to 2.41. Note that the interval is quite wide, considering the small difference between the sample means.

A second glance at the data reveals a marked inconsistency with this conclusion. We note that the wear measurement for the type A is larger than the corresponding value for type B for *each* of the five automobiles. These differences, recorded as $d = A - B$, are shown below.

AUTOMOBILE	$d = A - B$
1	.4
2	.4
3	.5
4	.6
5	.5
	$\bar{d} = .48$

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B
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9.4
11.8
9.1
8.3
$\bar{x}_2 = 9.76$

Suppose that we were to use x, the number of times that A is larger than B, as a test statistic, as was done in Exercise 21, Chapter 6. Then the probability that A would be larger than B on a given automobile, assuming no difference between the wearing quality of the tires, would be $p = 1/2$, and x would be a binomial random variable.

If we choose $x = 0$ and $x = 5$ as the rejection region for a two-tailed test, then $\alpha = P(0) + P(5) = 2(1/2)^5 = 1/16$. We would then *reject* H_0: $\mu_1 = \mu_2$ with a probability of a type I error equal to $\alpha = 1/16$. Certainly this is evidence to indicate that a difference exists in the mean wear of the two tire types.

The reader will note that we have employed two different statistical tests to test the same hypothesis. Is it not peculiar that the t-test, which utilizes more information (the actual sample measurements) than the binomial test, fails to supply sufficient evidence for rejection of the hypothesis $\mu_1 = \mu_2$?

The explanation of this seeming inconsistency is quite simple. The t-test described in Section 9.3 is *not* the proper statistical test to be used for our example. The statistical test procedure, Section 9.3, required that the two samples be *independent* and random. Certainly, the independence requirement was violated by the manner in which the experiment was conducted. The (pair of) measurements, an A and a B, for a particular automobile are definitely related. A glance at the data will show that the readings are of approximately the same magnitude for a particular automobile but vary from one automobile to another. This, of course, is exactly what we might expect. Tire wear, in a large part, is determined by driver habits, the balance of the wheels, and the road surface. Since each automobile had a different driver, we would expect a large amount of variability in the data from one automobile to another.

The familiarity we have gained with interval estimation has shown that the width of the large and small sample confidence intervals will depend upon the magnitude of the standard deviation of the point estimator of the parameter. The smaller its value, the better the estimate and the more likely that the test statistic will reject the null hypothesis if it is, in fact, false. Knowledge of this phenomenon was utilized in *designing* the tire wear experiment.

The experimenter would realize that the wear measurements would vary greatly from auto to auto and that this variability could not be separated from the data if the tires were assigned to the ten wheels in a *random* manner. (A random assignment of the tires would have implied that the data be analyzed according to the procedure of Section 9.3.) Instead, a comparison of the wear between the tire

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types A and B made on each automobile resulted in the five difference measurements. This design eliminates the effect of the car-to-car variability and yields more information on the mean difference in the wearing quality for the two tire types.

The proper analysis of the data would utilize the five difference measurements to test the hypothesis that the average difference is equal to zero, a statement which is equivalent to $H_0\colon \mu_1 = \mu_2$.

The reader may verify that the average and standard deviation of the five difference measurements are

$$\bar{d} = .48,$$

$$s_d = .0837.$$

Then,

$$H_0\colon \mu_d = 0$$

and

$$t = \frac{\bar{d} - 0}{s_d/\sqrt{n}} = \frac{.48}{.0837/\sqrt{5}} = 12.8.$$

The critical value of t for a two-tailed statistical test, $\alpha = .05$ and four degrees of freedom, is 2.776. Certainly, the observed value of $t = 12.8$ is extremely large and highly significant. Hence we would conclude that the average amount of wear for tire type B is less than that for type A.

A 95% confidence interval for the difference between the mean wear would be

$$\bar{d} \pm t_{\alpha/2} s_d/\sqrt{n} = .48 \pm (2.776)\frac{(.0837)}{\sqrt{5}}$$

or $.48 \pm .10$.

The statistical design of the tire experiment represents a simple example of a *randomized block design* and the resulting statistical test is often called a *paired difference* test. The reader will note that the pairing occurred when the experiment was planned and *not* after the data was collected. Comparisons of tire wear were made within relatively homogeneous blocks (automobiles) with the tire types *randomly* assigned to the two automobile wheels.

An indication of the gain in the amount of information obtained by blocking the tire experiment may be observed by comparing the calculated confidence interval for the unpaired (and incorrect) analysis with the interval obtained for the paired difference analysis. The confidence interval for $(\mu_1 - \mu_2)$ that might have been calculated,

Exhibit TMZ-R5
Page 7 of 7

had the tires been randomly assigned to the ten wheels (unpaired), is unknown but likely would have been of the same magnitude as the interval -1.45 to 2.41, calculated by analyzing the observed data in an unpaired manner. Pairing the tire types on the automobiles (blocking) and the resulting analysis of the differences produced the interval estimate .38 to .58. Note the difference in the width of the intervals indicating the very sizeable increase in information obtained by blocking in this experiment.

While blocking proved to be very beneficial in the tire experiment, this may not always be the case. We observe that the degrees of freedom available for estimating σ^2 is less for the paired than for the corresponding unpaired experiment. If there were actually no difference between the blocks, the reduction in the degrees of freedom would produce a moderate increase in the $t_{\alpha/2}$ employed in the confidence interval and hence increase the width of the interval. This, of course, did not occur in the tire experiment because the large reduction in the standard deviation of $\bar{d}$ more than compensated for the loss in degrees of freedom.

9.6 Inference Concerning a Population Variance

We have seen in the preceding sections that an estimate of the population variance, σ^2, is fundamental to procedures for making inferences about population means. Moreover, there are many practical situations where σ^2 is the primary objective of an experimental investigation, thus it assumes a position of far greater importance than that of the population mean.

Scientific measuring instruments must provide unbiased readings with a very small error of measurement. An aircraft altimeter that measured the correct altitude on the *average* would be of little value if the standard deviation of the error of measurement were 5000 feet. Indeed, bias in a measuring instrument can often be corrected but the precision of the instrument, measured by the standard deviation of the error of measurement, is usually a function of the design of the instrument itself and cannot be controlled.

Machined parts in a manufactured process must be produced with minimum variability in order to reduce out-of-size and hence defective products. And, in general, it is desirable to maintain a minimum variance in the measurements of the quality characteristics of an industrial product in order to achieve process control and therefore minimize the percentage of poor quality product.